CALIFORNIA
ENERGY
COMMISSION

2005 ENVIRONMENTAL PERFORMANCE REPORT OF CALIFORNIA'S ELECTRICAL GENERATION SYSTEM

Appendices A thru D

STAFF REPORT

June 2005
CEC-700-2005-016-AP-A

Arnold Schwarzenegger, *Governor*

Table of Contents

APPENDIX A: SUPPORTING TECHNICAL ANALYSIS FOR THE AIR QUALITY CHAPTER

This appendix of the Air Section of the 2005 Environmental Performance Report provides analyses of monthly air emissions and air emissions trends of California electricity generating technologies in-state for the 2001 to 2003 time frame. “Emissionless” sources such as hydroelectric and nuclear are included to give the reader an appreciation of the air emissions footprint of electricity used. Additionally, statewide and regional trends are shown.

There are approximately 1,000 electricity generating facilities within California, and typically one to six units at each facility. The Electricity Assessments Office provided generation and fuel use data (as well as other relevant identification information) for each unit at each facility on a monthly basis from the QFER data files. This resulted in a database well over 45,000 records long representing over 61,000 MW of in-state electricity generating capacity shown in Table 1. While endeavors have been made to incorporate the recent EPR Forms database, significant disparity between unit identification and data within the QFER database and the EPR Forms database remains.

Table 1
Environmental Office Data Base of 2003 In-State Generation Technologies and Fuels (Nameplate Capacity MW)

	Solar	Coal	Natural Gas	Geo-thermal	Hydro	Nuclear	Waste-Energy	Liquid Fuel/Oil	Other	Unknw	Wind	GRAND TOTAL
Cogeneration		576	6,575				42		45	6		7,245
Combined Cycle			8,040							572		8,612
Geothermal				2,623								2,623
IC Engine			90					15				105
Large Hydro					12,017							12,017
Nuclear						4,456						4,456
Peaker			2,732					342				3,074
Small Hydro					1,271					2		1,273
Solar-PV/Gas	380											380
Steam Boiler			19,088									19,088
Waste-Energy			4				1,030			28		1,062
Wind											1,526	1,526
TOTALS	380	576	36,529	2,623	13,289	4,456	1,072	357	45	608	1,526	61,462

The staff of the Environmental Office identified an emission factors to use for each facility primarily from the EPR Forms,[1] and alternatively from the E-GRID database system, Commission files, or the EPA AP-42 Emission Factor Compendium. Significant efforts were made by the Environmental Office staff to validate the NO_x, CO2-eq and PM10 emission totals with existing emission inventories tabulated by the California Air Resources Board and the local air districts. While not a perfect match, EO staff is confident that the results show that the emission estimates presented are reasonably representative for the facilities in question and of the monthly generation and emission swings. The Environmental Office Staff believes that the slight emission inventory discrepancies stem from incorrect or old emission factors, missing generation units,[2] and units located in the wrong air districts or categories. The data provides comparative data on generation technology and fuel type across 36 months. However, the data and results shown should not be used for air quality planning or unit specific compliance.

These results should be viewed in the context of previous air emissions analyses. In the ***2001 Environmental Performance Report***[3] staff described the trends in air emissions from California generation facilities from 1975 to 2000. Environmental performance improved substantially during that time period, primarily due to switching from oil to natural gas, improvements in combustion technologies, and implementation of pollution controls. The ***2003 Environmental Performance Report***[4] analyzed recent trends in emissions, generation and emission control technologies, and air regulations for California electricity generation using fuel combustion for 1996 to 2002. A staff white paper to the ***2004 Update to the Integrated Energy Policy Report***[5] analyzed air pollutant emission trends from aging boiler units and the status of emission control technology retrofits.

California Generation 2001 to 2003

In order to evaluate the environmental footprint of the California generation units, staff evaluated Electricity Analysis Office monthly generation data for 2001 to 2003, supplemented by power plant and generation data from the US Energy Information Agency. Monthly generation data for 2001 through 2003 are shown in Figure 1 and Table 2, 3 and 4. Broken out on the figure and tables are the generation by technology or fuel type. Cogeneration output is fairly constant regardless of the season or overall demand, except for a dip in 2001 when the financial difficulties of the investor owned utilities created payment uncertainties for some cogenerators. Nuclear output is constant. In 2001, much of the load variation was shaped by the steam boilers and large hydroelectric. In 2003, the combustion turbine combined cycle and large hydroelectric sectors followed the seasonal demand variations. This figure does not include out-of state imports, but they are generally constant from year to year and month to month. Detailed generation data are provided in Tables 2, 3 and 4.

Table 1 2001 Monthly California Generation (GWhr)

2001 GWhrs	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
Cogeneration	3,809	3,058	2,575	2,558	3,258	3,441	3,607	3,807	3,542	3,670	3,462	3,812	40,600
Combined Cycle	482	425	309	392	383	294	1,010	935	1,003	814	705	523	7,274
Geothermal	1,220	1,081	1,182	1,095	1,079	1,091	1,200	1,141	1,101	1,107	1,104	1,122	13,525
IC Engine	3	3	3	3	3	19	11	20	12	14	20	16	125
Large Hydro	1,303	882	1,264	1,542	2,623	2,631	2,546	2,507	1,626	1,543	1,039	1,410	20,916
Nuclear	2,390	2,230	2,469	2,319	1,668	3,110	3,295	3,280	3,165	3,015	3,068	3,287	33,294
Peaker	393	242	164	153	214	143	148	138	108	131	137	138	2,109
Small Hydro	236	252	327	370	446	414	375	356	309	268	235	384	3,973
Solar (PV/Gas)	17	13	44	60	91	112	119	117	121	49	62	30	836
Steam Boiler	6,361	5,822	6,748	5,999	6,196	5,880	6,861	7,261	6,055	5,131	3,707	3,937	69,961
Waste-Energy	513	418	410	395	400	501	486	511	475	473	469	561	5,612
Wind	153	158	241	371	360	370	376	355	320	226	146	166	3,242
TOTAL	16,882	14,584	15,735	15,256	16,721	18,007	20,034	20,428	17,838	16,443	14,155	15,385	201,469

Figure 1 2001 to 2003 Monthly Generation (GWhr)

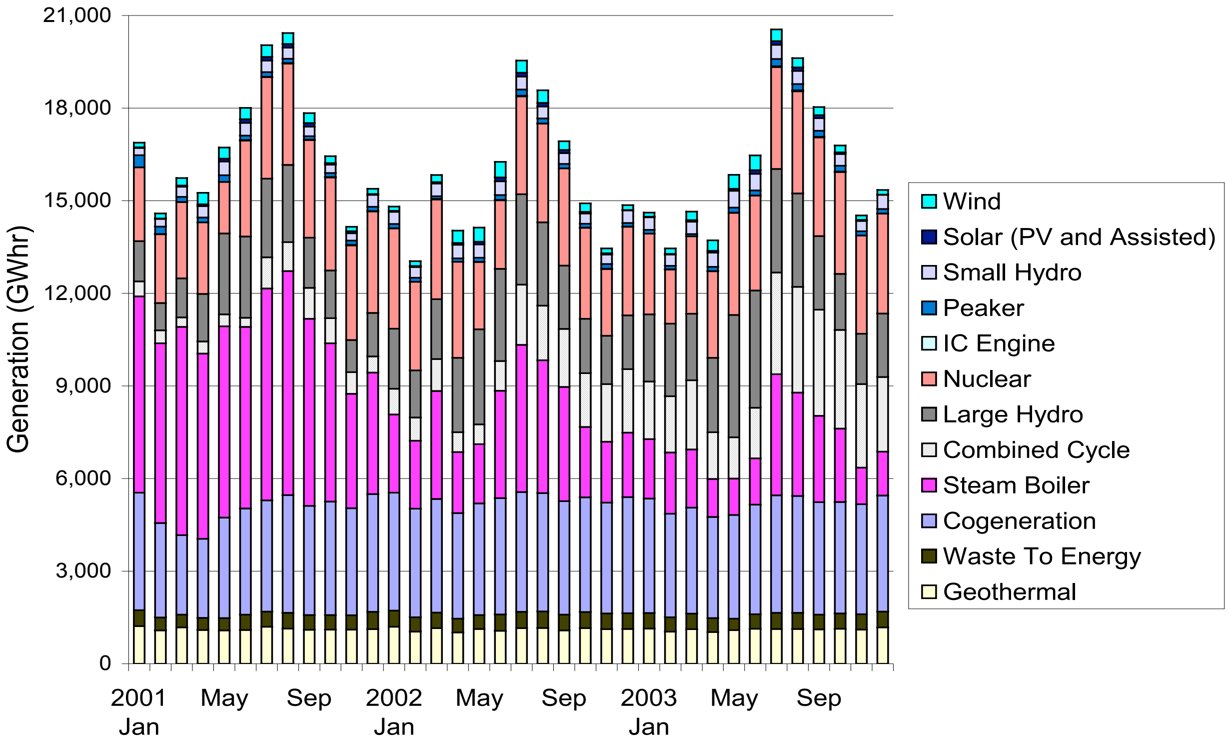


Table 2 2002 Monthly California Generation (GWhr)

2002 GWhrs	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
Cogeneration	3,815	3,517	3,684	3,420	3,613	3,769	3,877	3,830	3,672	3,719	3,589	3,762	44,268
Combined Cycle	832	752	1,035	641	640	962	1,956	1,767	1,880	1,742	1,865	2,061	16,134
Geothermal	1,201	1,043	1,150	1,018	1,128	1,066	1,153	1,157	1,079	1,156	1,117	1,126	13,396
IC Engine	9	5	19	3	5	12	18	8	4	8	12	7	110
Large Hydro	1,951	1,523	1,939	2,411	3,077	2,989	2,927	2,699	2,052	1,760	1,567	1,737	26,630
Nuclear	3,247	2,869	3,227	3,111	2,182	2,218	3,168	3,196	3,150	2,949	2,163	2,872	34,353
Peaker	133	126	86	111	131	161	206	165	143	125	151	119	1,656
Small Hydro	396	348	412	437	432	443	419	381	343	328	303	401	4,644
Solar (PV/Gas)	30	33	46	61	87	123	125	122	110	55	42	18	851
Steam Boiler	2,534	2,206	3,495	1,978	1,925	3,477	4,767	4,305	3,701	2,280	1,974	2,088	34,732
Waste-Energy	524	461	507	442	451	530	530	541	512	518	515	510	6,040
Wind	137	162	231	395	457	504	391	403	280	272	158	156	3,546
TOTAL	14,808	13,045	15,831	14,027	14,128	16,255	19,539	18,575	16,926	14,912	13,455	14,858	186,359

Table 3 2003 Monthly California Generation (GWhr)

2003 GWhrs	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
Cogeneration	3,705	3,351	3,429	3,271	3,359	3,545	3,803	3,784	3,644	3,609	3,563	3,762	42,825
Combined Cycle	1,866	1,821	2,238	1,514	1,338	1,635	3,296	3,427	3,440	3,202	2,708	2,414	28,899
Geothermal	1,138	1,040	1,122	1,026	1,085	1,133	1,129	1,124	1,113	1,132	1,110	1,177	13,329
IC Engine	4	4	3	3	5	9	27	29	19	11	3	2	119
Large Hydro	2,174	2,352	2,155	2,410	3,961	3,801	3,357	3,023	2,387	1,812	1,626	2,058	31,117
Nuclear	2,611	1,754	2,508	2,805	3,310	3,071	3,298	3,311	3,198	3,304	3,186	3,237	35,594
Peaker	125	114	67	141	163	161	236	205	192	192	133	146	1,876
Small Hydro	405	365	405	454	545	535	459	425	411	375	335	456	5,171
Solar (PV/Gas)	17	17	49	59	70	124	118	115	95	54	32	10	759
Steam Boiler	1,928	1,989	1,891	1,234	1,175	1,503	3,924	3,347	2,792	2,372	1,184	1,421	24,760
Waste-Energy	509	467	503	457	378	474	523	529	479	501	495	514	5,829
Wind	129	179	275	344	452	478	377	302	262	224	143	150	3,316
TOTAL	14,610	13,454	14,645	13,717	15,841	16,470	20,547	19,621	18,033	16,788	14,519	15,347	193,592

Finding: Month to month, in-state cogeneration and nuclear operate on a fairly constant basis. In-state steam boilers, combustion turbine combined cycles and large hydroelectric provide much of the monthly energy and the seasonal load following.

Generation Air Emissions 2001 to 2003

Staff used emission factors air districts, California Air Resources Board (CARB) and the 2005 Environmental Data Request forms from owners to evaluate monthly emissions as shown in Figures 2, 3 and 4. Figure 2 shows that emissions of oxides of nitrogen for the state are dominated by cogeneration, steam boilers, and surprisingly, waste to energy. Figure 1 shows the large generation contribution from cogeneration and steam boilers, but waste to energy oxides of nitrogen appear to be out of proportion to its generation.

Similarly, statewide generation particulate matter (PM10) inventories are dominated by emissions from cogeneration and steam boilers. This is expected as the waste to energy can be solid fueled, such as biomass and petroleum coke fuels, which that tend to have higher particulate emission rates than natural gas. The statewide emissions of carbon dioxide-equivalent gases are dominated by contributions from cogenerators, steam boilers and later in 2003, by combustion turbine combined cycles.

Control of CO2 from Generation

One of the simplest and cheapest CO2 control measures that many states and countries may implement is switching from coal and oil to natural gas-fired generation. Coal and oil produce about 1.8 and 1.4 times, respectively, as much carbon per mmBtu as natural gas (ICF 1999). Because a significant amount of California generation already uses natural gas, whether for cost, ease of permitting, or air quality compliance, the state has fewer opportunities in the generation sector to switch to natural gas for additional CO2 reductions.

Figure 2 2001 to 2003 Generation NOx (tons per month) and Emission Factor (lbs/MWhr)

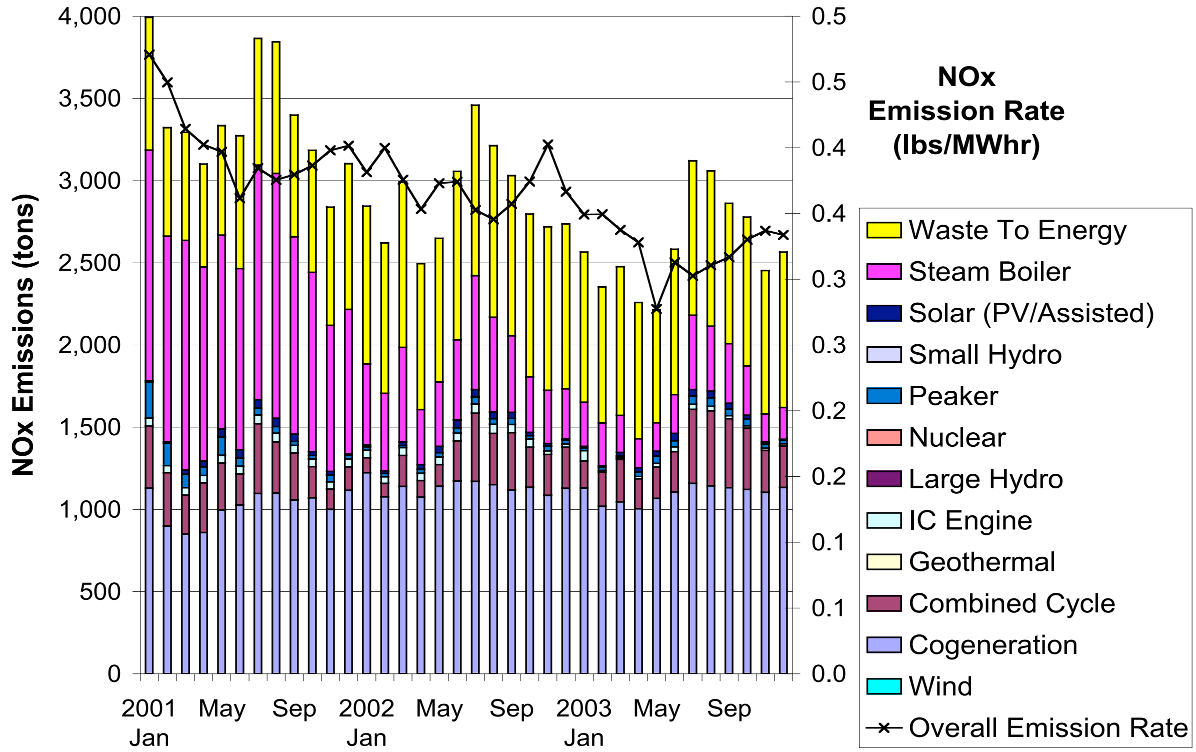


Figure 3 2001 to 2003 Generation PM10 (tons per month) and Emission Factor (lbs/MWhr)

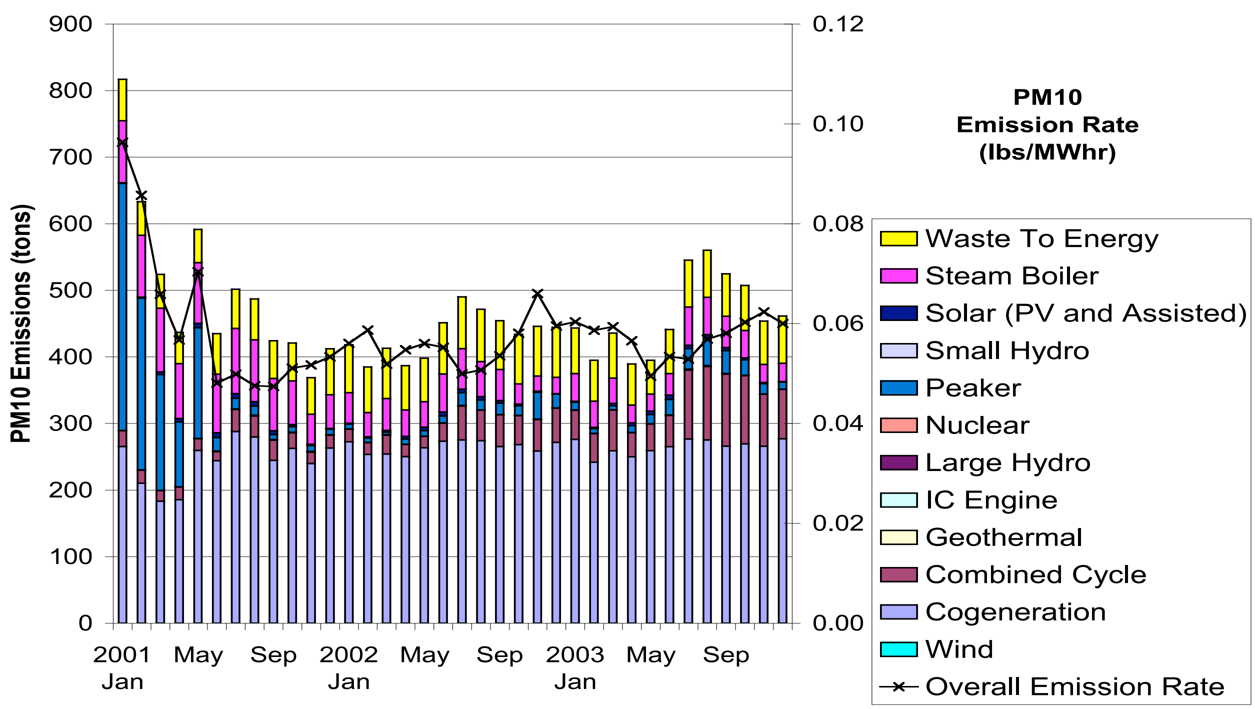
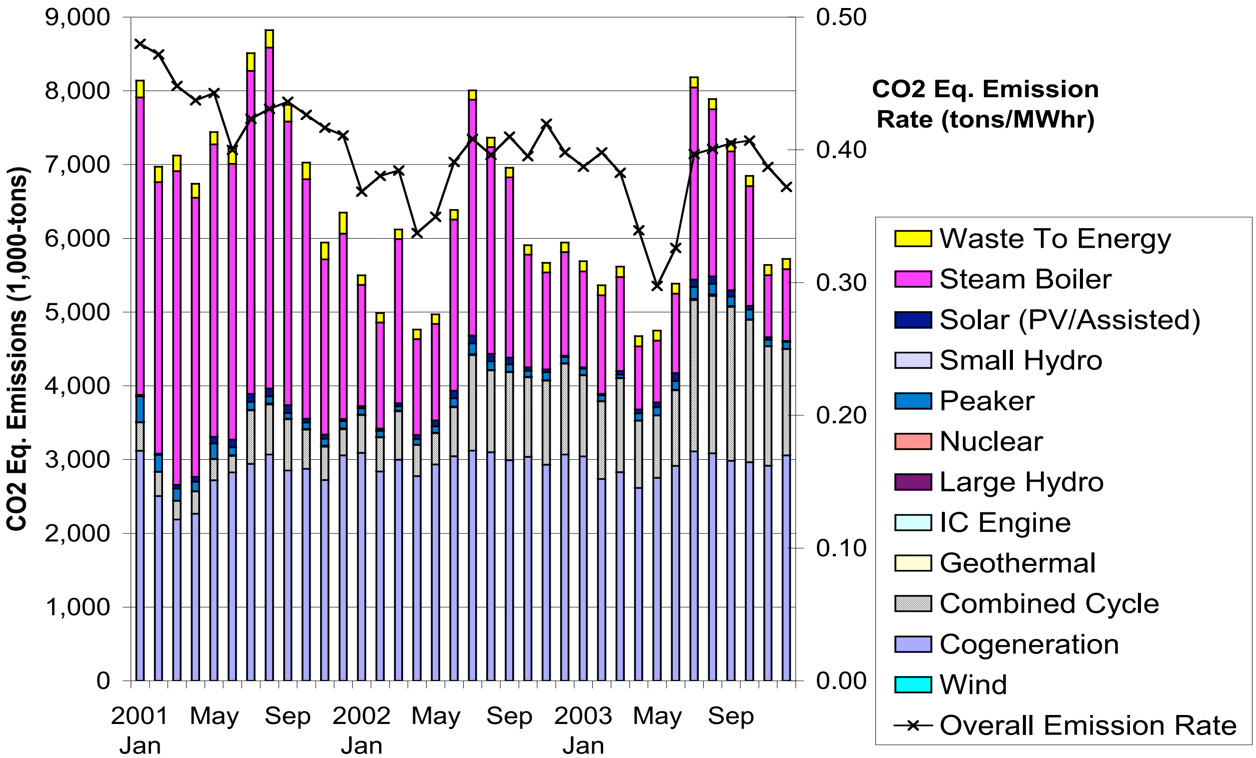


Figure 4 2001 to 2003 Generation CO_2 (million tons per month) and Emission Factor (tons/MWhr)

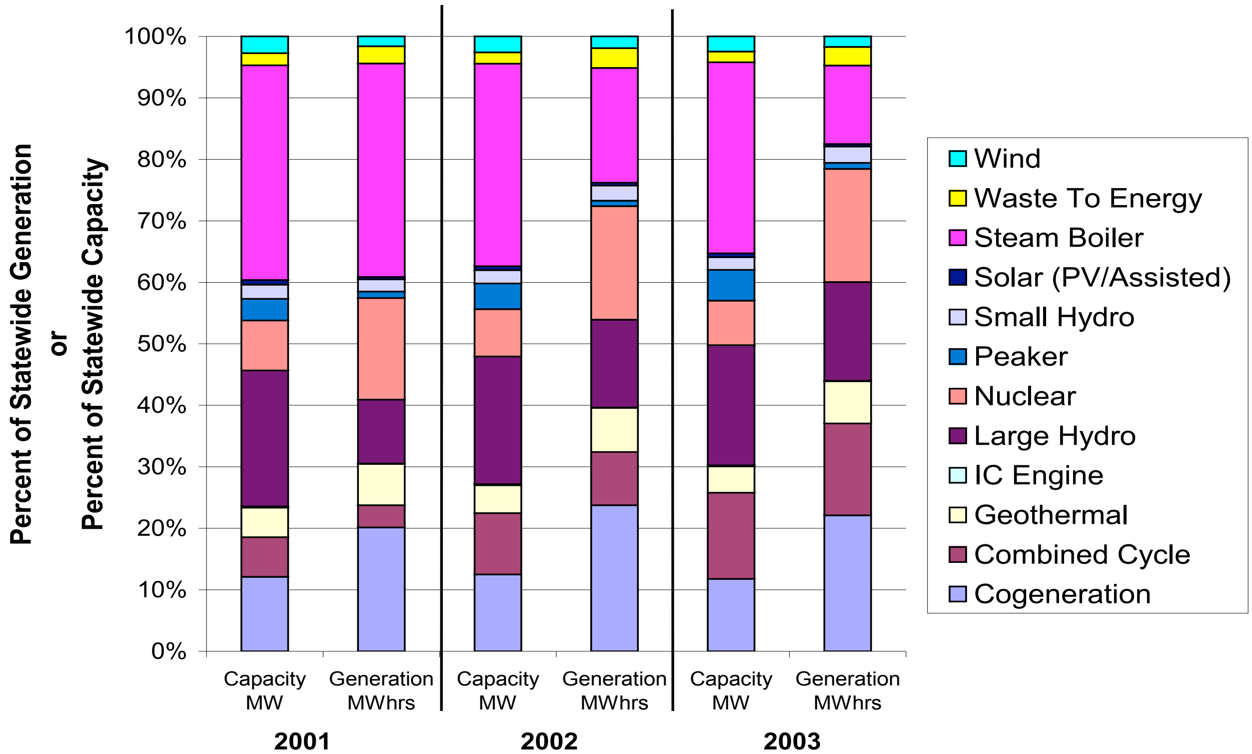


In order to understand one of the reasons why cogeneration or steam boilers tend to dominate the emission inventories, Figure 5 compares the installed megawatts (capacity) to the annual gigawatt-hours (operation). Even though cogeneration is about ten percent of the installed capacity, it generates about twenty percent of the annual energy. Nuclear has a similar relationship between capacity and energy production. Steam boilers, on the other hand, are about 35 percent of the installed capacity and about 35 percent of the energy. In other words, the cogenerators are baseloaded, as shown in Figure 1, and therefore have impacts on the emissions inventories beyond their capacity. The steam boilers, while being a large portion of the in-state generation, operate less, or load follow, and have less of an effect on the emissions inventory than suggested by the magnitude of their installed capacity. Also, as shown later in the Technology section below, there are also differences in their emission factors that affect their relative contributions to the monthly emissions inventories.

- **Finding:** Statewide generation oxides of nitrogen are dominated by emissions contributions from the cogeneration and waste to energy sectors.

- **Finding:** As new combined cycle units came on-line in 2003, they are contributed increasingly to generation and carbon dioxide-equivalent emission inventories.

Figure 5 2001 to 2003 Installed Capacity (MW) vs Generation (MWhr



Generation Technology Air Emissions

Emissions and emission trends from power generation depend on the generation technology, the energy source, and the air emission controls and regulations. This section focuses on the "fired" portion of the power system, because generation by solar photovoltaics, wind, nuclear, or hydroelectric processes generally avoid air emissions from fuel combustion. Geothermal generation, while not firing fuels, can emit quantities of hydrogen sulfide, ammonia, mercury, and carbon dioxide, but these are not presented here.

Fired units can be found operating throughout the state, with capacities ranging from one kilowatt to thousands of megawatts. The units are primarily either fuel-fired boilers supplying steam to a turbine or fossil fuel-fired combustion turbines operating in simple-cycle mode (just the combustion turbine) or combined-cycle mode (using the waste heat to generate steam to run a steam turbine). Internal combustion or reciprocating engines are only one percent of the total installed capacity that is fuel-fired. The boiler/steam turbine power plants have efficiencies that range from about 30 percent to near 40 percent. Older simple-cycle combustion turbines are less than 30 percent efficient, while modern simple-cycle turbines are approaching 40 percent. Most of the new capacity that has been added to the system in recent years in California consists of combined-cycle power plants that can be greater than 55 percent efficient. As the fired generation fleet turns over, with these new facilities replacing boilers and less efficient combustion turbines, total emissions and emissions per MWh will improve.

Electric generating station fuel types include agricultural and wood waste, coal/petroleum coke, diesel, digester gas, distillate oil, landfill gas, municipal solid waste, process/refinery gas, and natural gas. The largest, and fastest growing, segment of the generating capacity in California is fueled by natural gas. Natural gas is the preferred fuel because of its cleaner combustion compared to other fuels. It has negligible sulfur, which limits sulfur compound emissions; negligible ash, which limits PM10 emissions; and NOx emission rates that are generally lower than from other fuels.

Natural Gas-Fired Steam Boilers

Figure 22 2001 to 2003 Natural Gas-Fired Steam Boilers NOx (tons per month) and Emission Factor (lbs/MWhr)

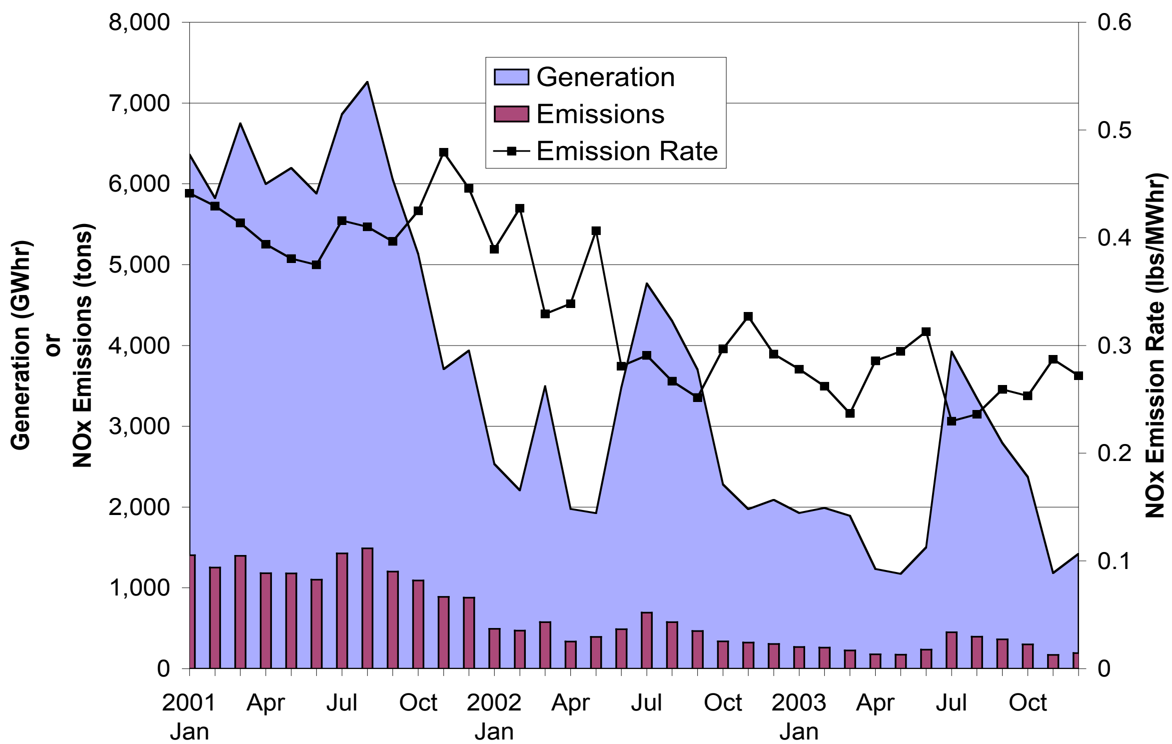


Figure 23 2001 to 2003 Natural Gas-Fired Steam Boilers PM10 (tons per month) and Emission Factor (lbs/MWhr)

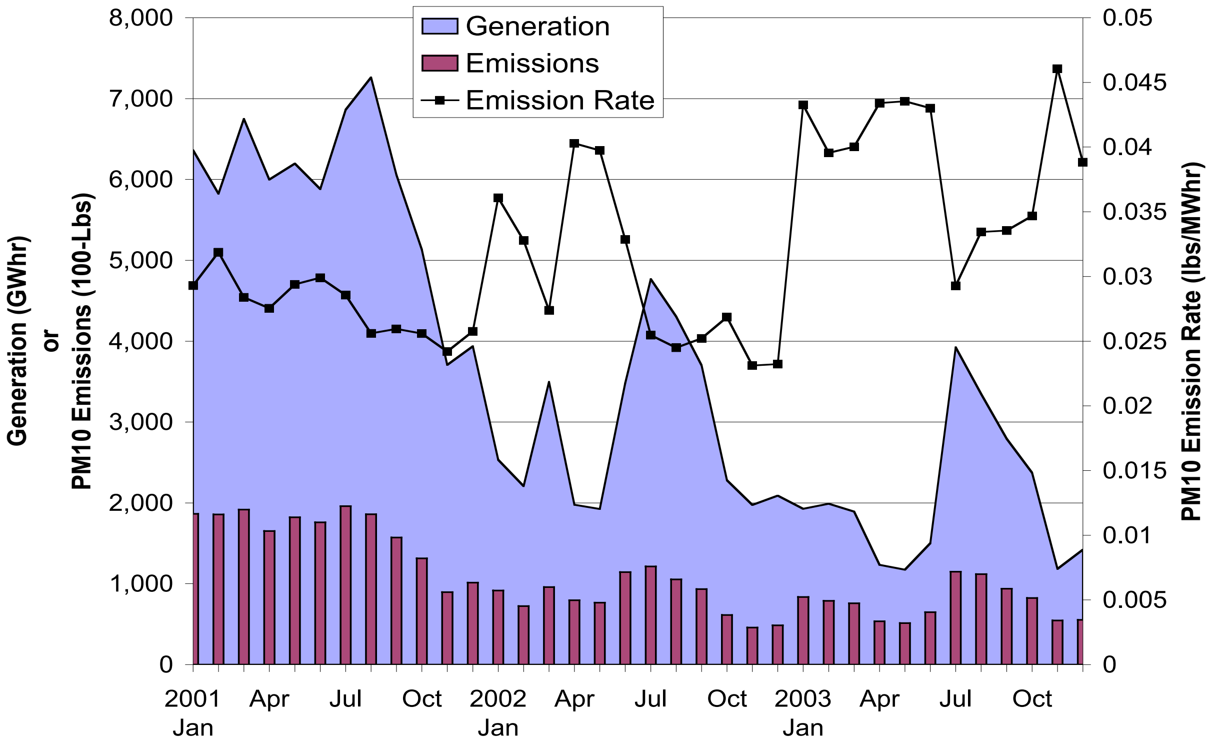
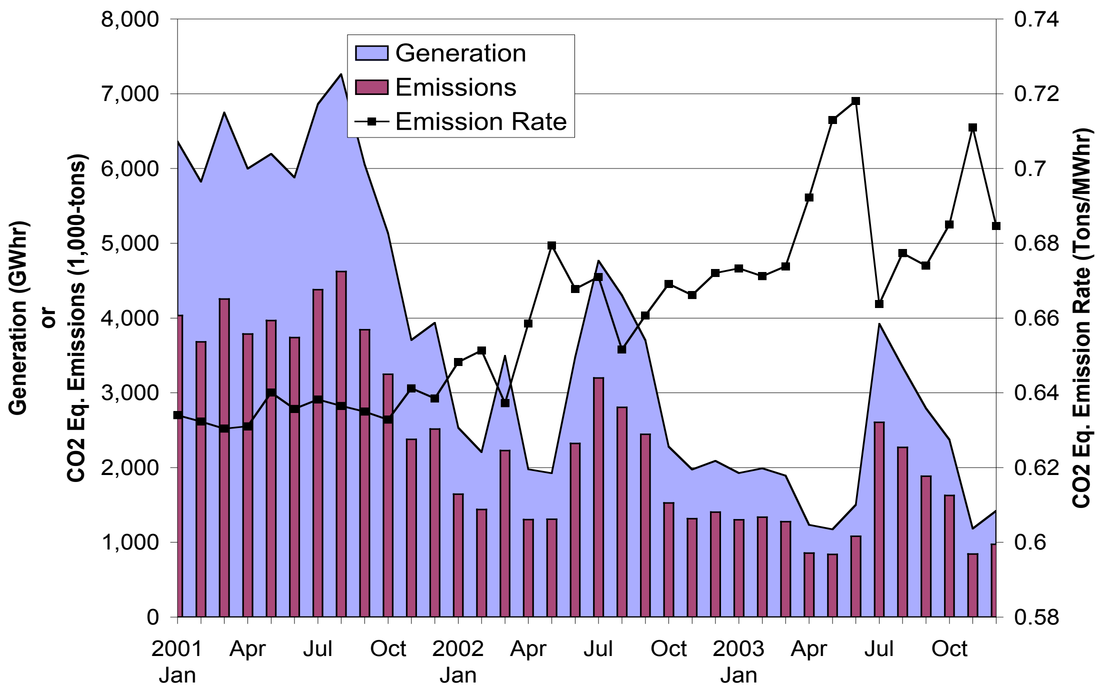
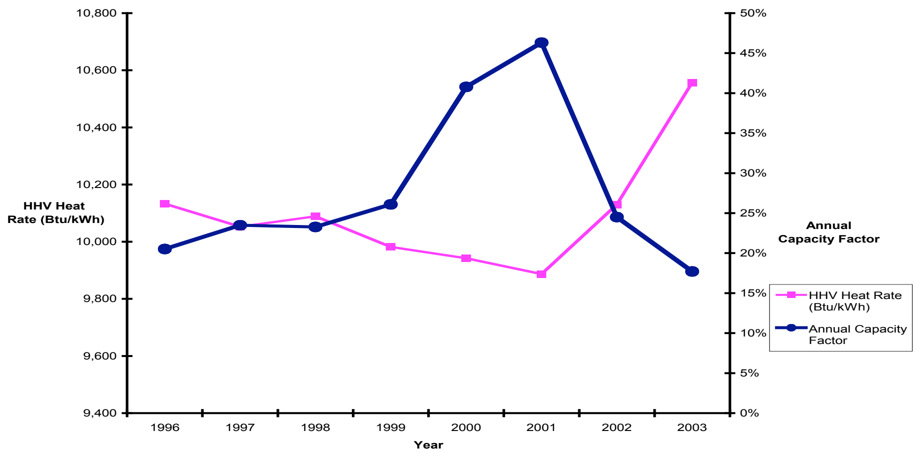


Figure 24 2001 to 2003 Natural Gas-Fired Steam Boilers CO_2 (million tons per month) and Emission Factor (tons/MWhr)



This carbon dioxide-equivalent emission factor shows the effect unit dispatch: increased dispatch equals improved heat rate – decreased dispatch equals degrading heat rate. Over the 2001 to 2003 time period, the steam boilers (the “aging units” of the 2004 IEPR Update) experienced significant reductions in monthly output, and the emission factor increased by over ten percent. This effect is shown in Figure 25 for the aging units.

Figure 25 Aging Unit Heat Rate (Btu/kWhr) as a Function of Dispatch



- **Finding:** The steam boilers oxides of nitrogen emission factor has improved.

- **Finding:** Decreased use of steam boilers for electricity generation degrades the fleet average heat rate, particulate matter emission factor, and the carbon dioxide-equivalent emission factor.

Combustion Turbine Combined Cycle

Figure 26 2001 to 2003 Combustion Turbine Combined Cycle NOx (tons per month) and Emission Factor (lbs/MWhr)

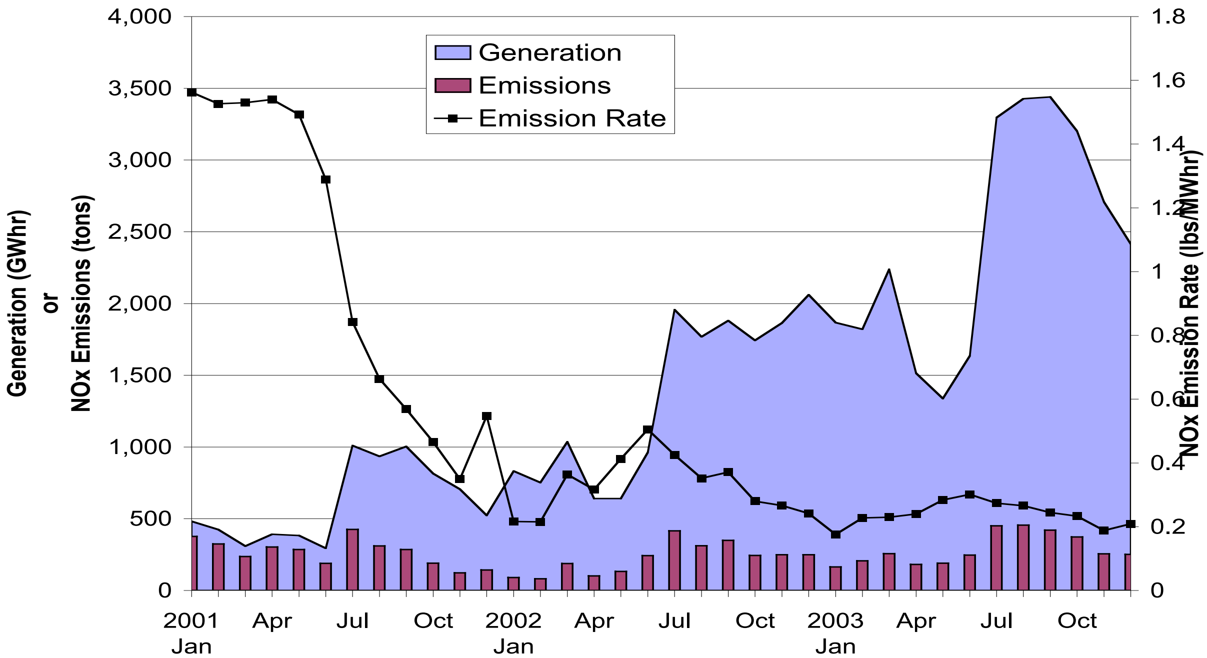


Figure 27 2001 to 2003 Combustion Turbine Combined Cycle PM10 (tons per month) and Emission Factor (lbs/MWhr)

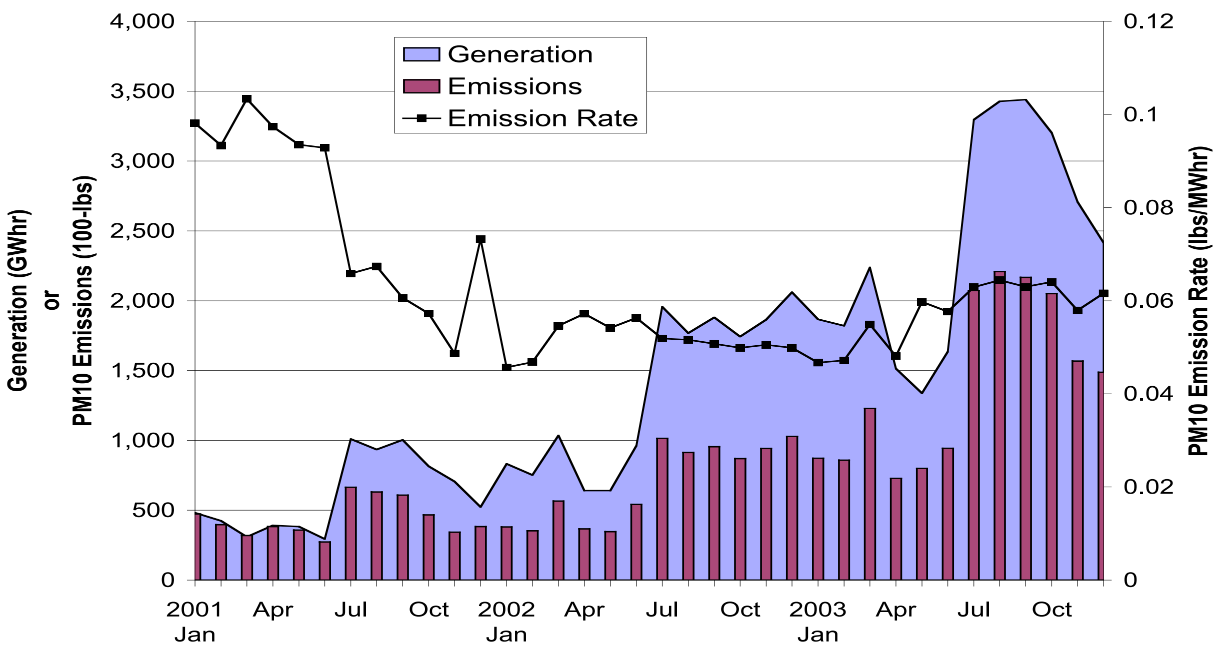
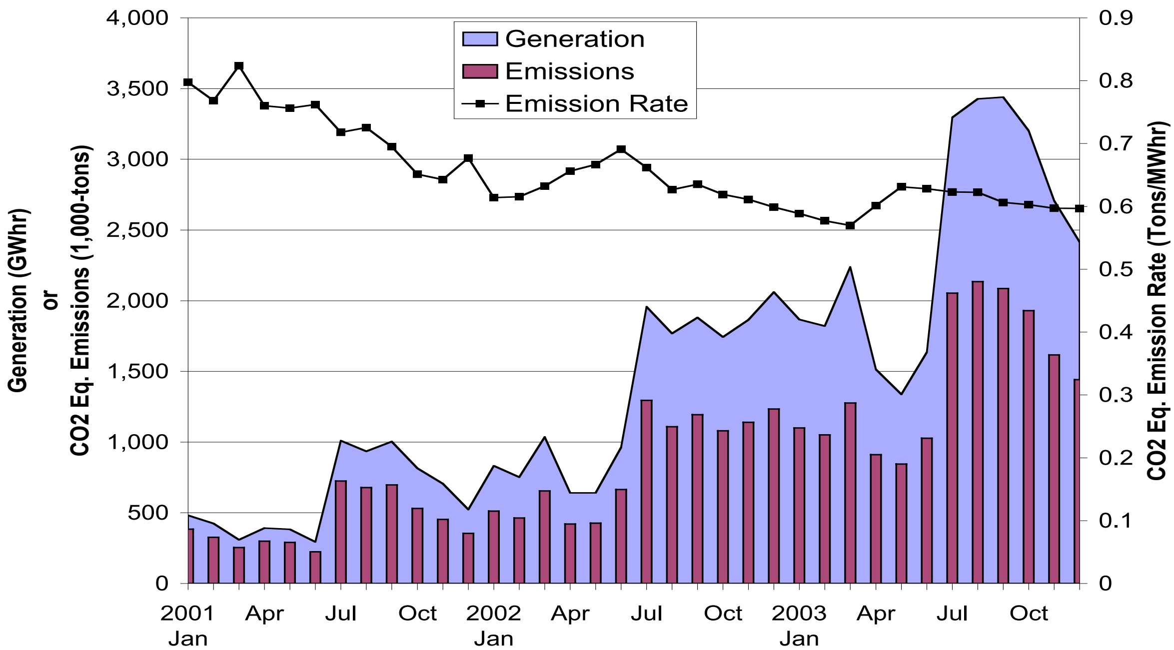


Figure 28 2001 to 2003 Combustion Turbine Combined Cycle CO_2 (million tons per month) and Emission Factor (tons/MWhr)



- **Finding:** The combined cycle units oxides of nitrogen fleet average emission factor has improved dramatically over the three year time period.

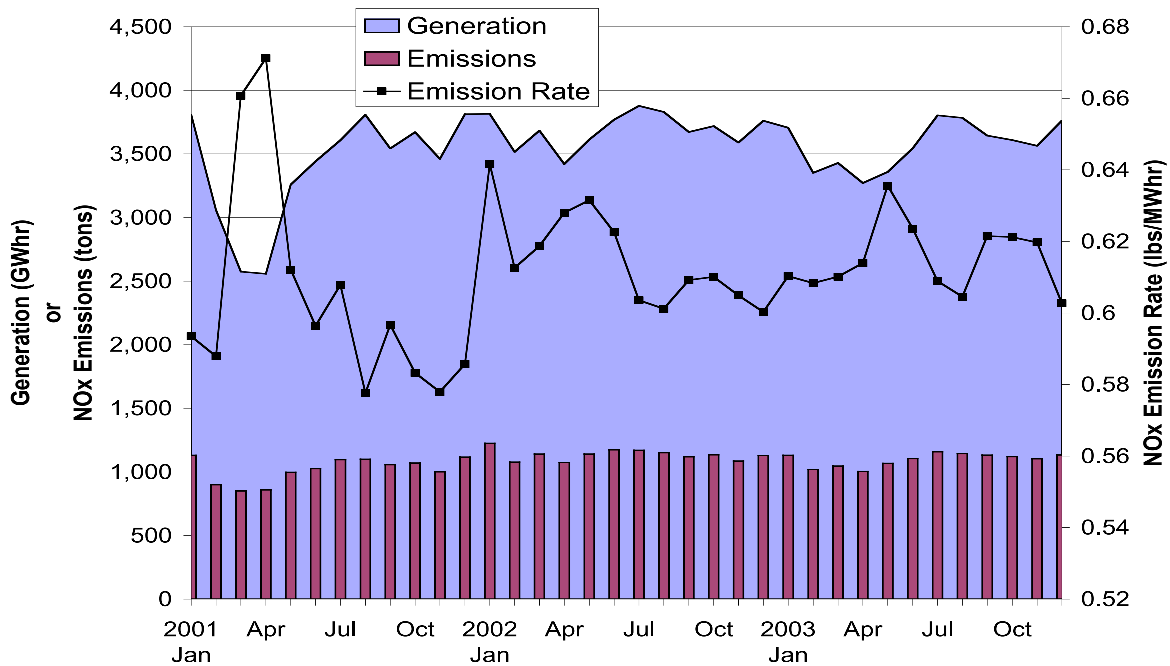
- **Finding:** The installed capacity and energy production, particulate matter and carbon dioxide equivalent emissions of the combined cycles have increased dramatically over the three year time period.

Cogeneration

Cogeneration is defined by the sequential use of fuel energy to generate electricity and provide some useful thermal heat to a process. In most cases, electricity is generated first and the heat energy is extracted from the flue gas for the process. Some units capture as little as five percent of the energy input as useful thermal. Others, like some of the TEORs in San Joaquin, can capture about twenty percent of the input energy for the process. The emission factors below are based on the electricity output only and do not weight the potential energy and emissions savings from avoiding a process boiler. Therefore, the emission factors are probably too high but still representative of the relative contribution of cogeneration to emissions compared to other in-state generating technologies.

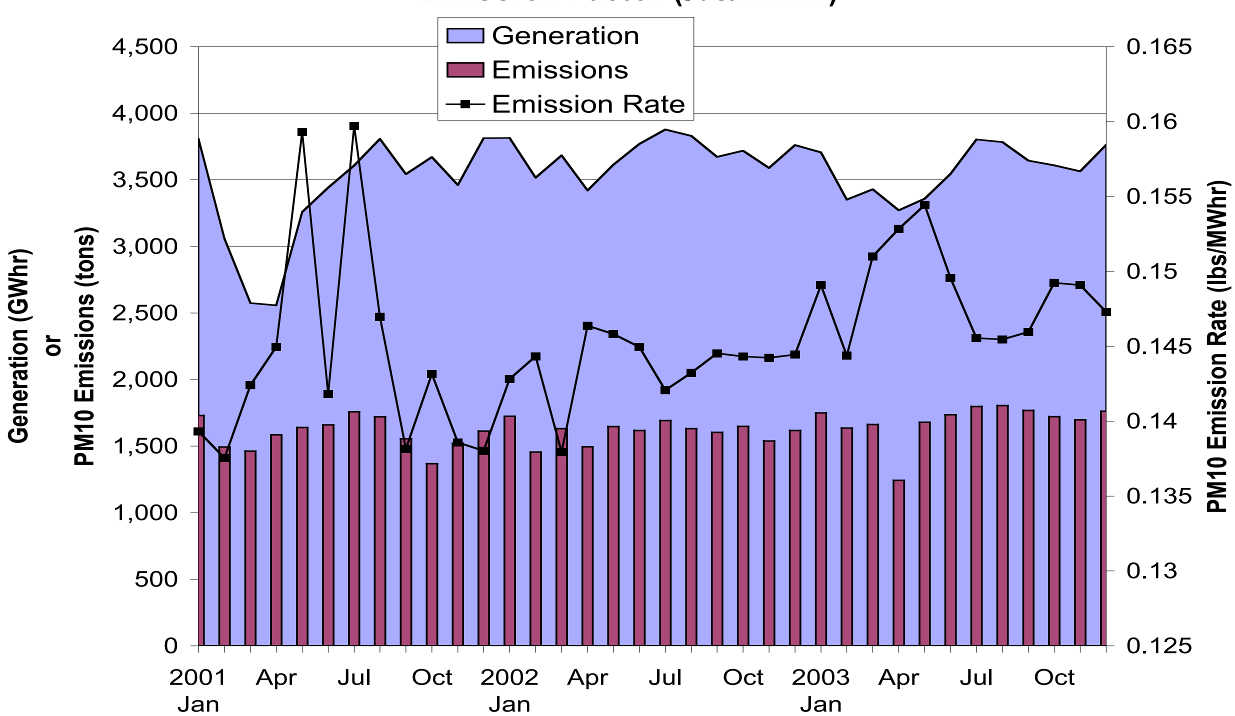
California cogeneration emission factors are higher than most other technologies for several other reasons. Most of its cogeneration fleet was built in the 1980's and 1990's. Emission control and generation technologies have evolved since then. Additionally, some cogenerators use lower quality fuels such as biomass, waste, coal, shredded tires and petroleum coke, which are more difficult to combust efficiently and cleanly.

Figure 29 2001 to 2003 Cogeneration NOx (tons per month) and Emission Factor (lbs/MWhr)



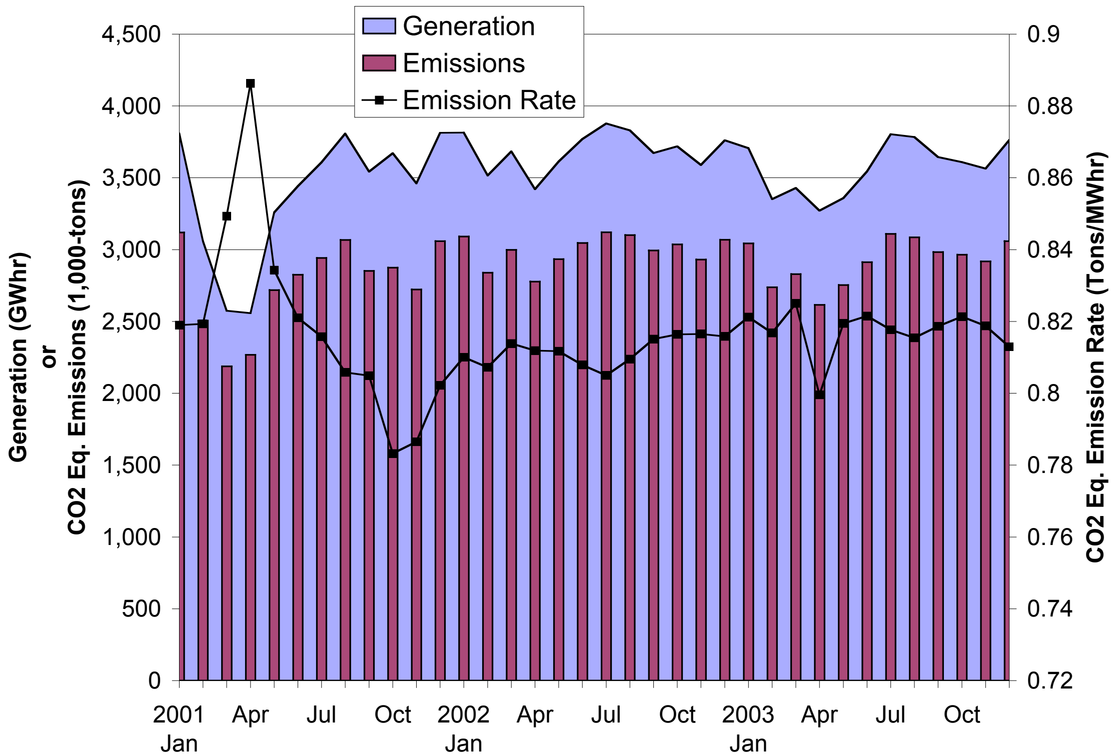
Note: not corrected for useful thermal output

Figure 30 2001 to 2003 Cogeneration PM10 (tons per month) and Emission Factor (lbs/MWhr)



Note: not corrected for useful thermal output

Figure 31 2001 to 2003 Cogeneration CO_2 (million tons per month) and Emission Factor (tons/MWhr)



Note: not corrected for useful thermal output

- **Finding:** The cogeneration oxides of nitrogen average emission factors are much higher than the system averages.
- **Finding:** The cogeneration particulate matter average emission factors are much higher than the system averages.
- **Finding:** The cogeneration carbon dioxide-equivalent average emission factors are higher than the system averages.

Simple Cycle Peaking Combustion Turbines

Figure 32 2001 to 2003 Simple Cycle Peaking Combustion Turbines NOx (tons per month) and Emission Factor (lbs/MWhr)

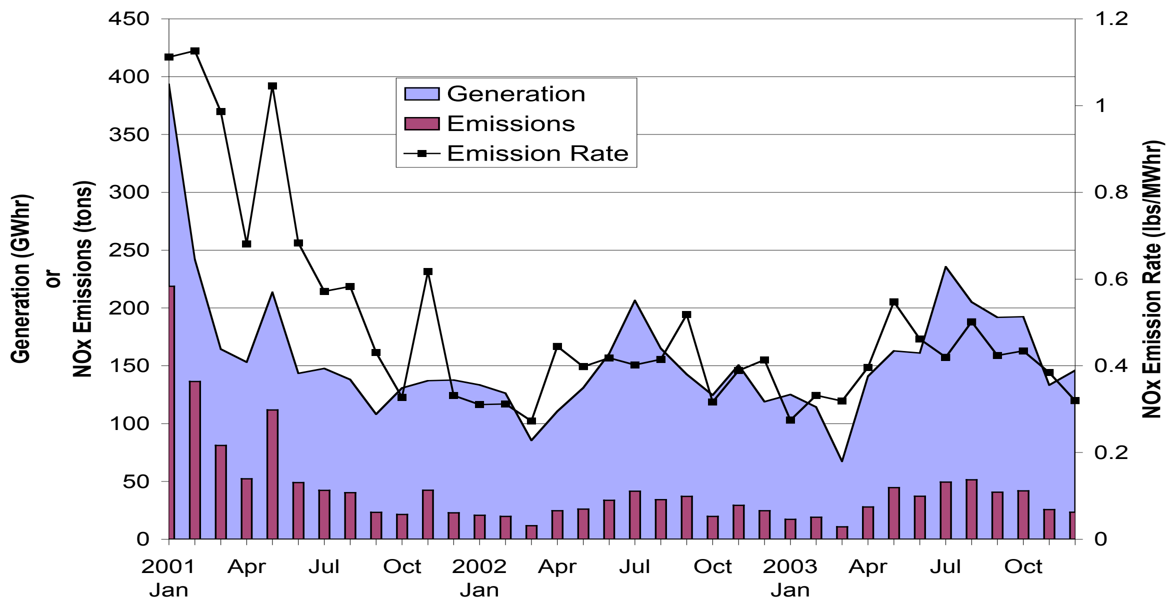


Figure 33 2001 to 2003 Simple Cycle Peaking Combustion Turbines PM10 (tons per month) and Emission Factor (lbs/MWhr)

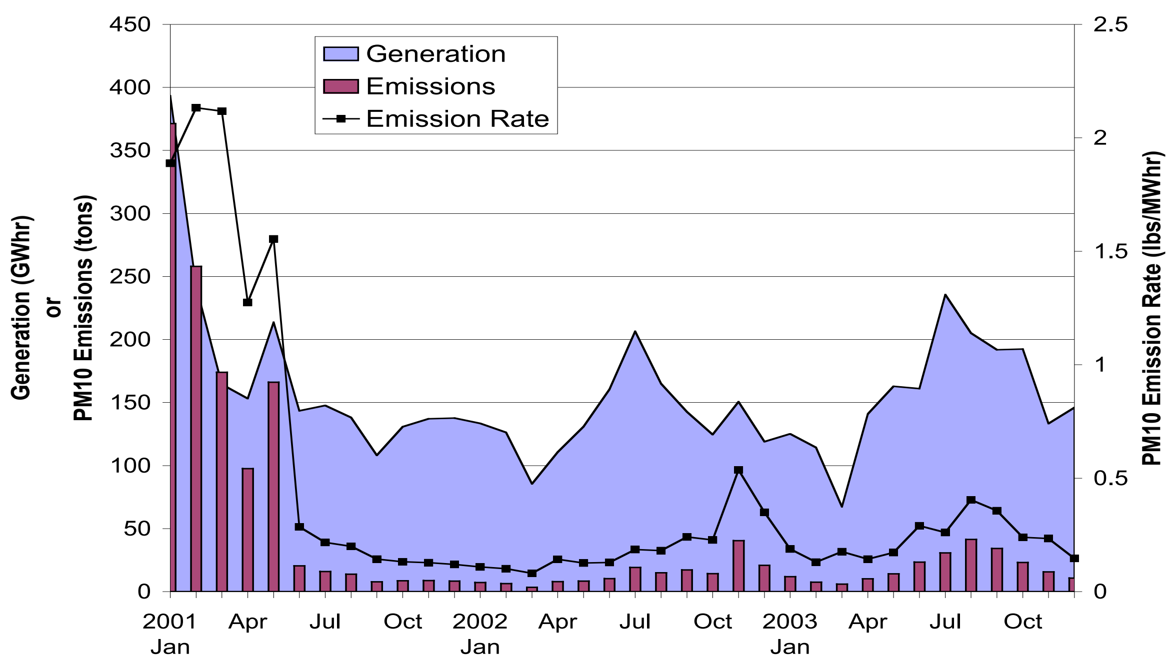
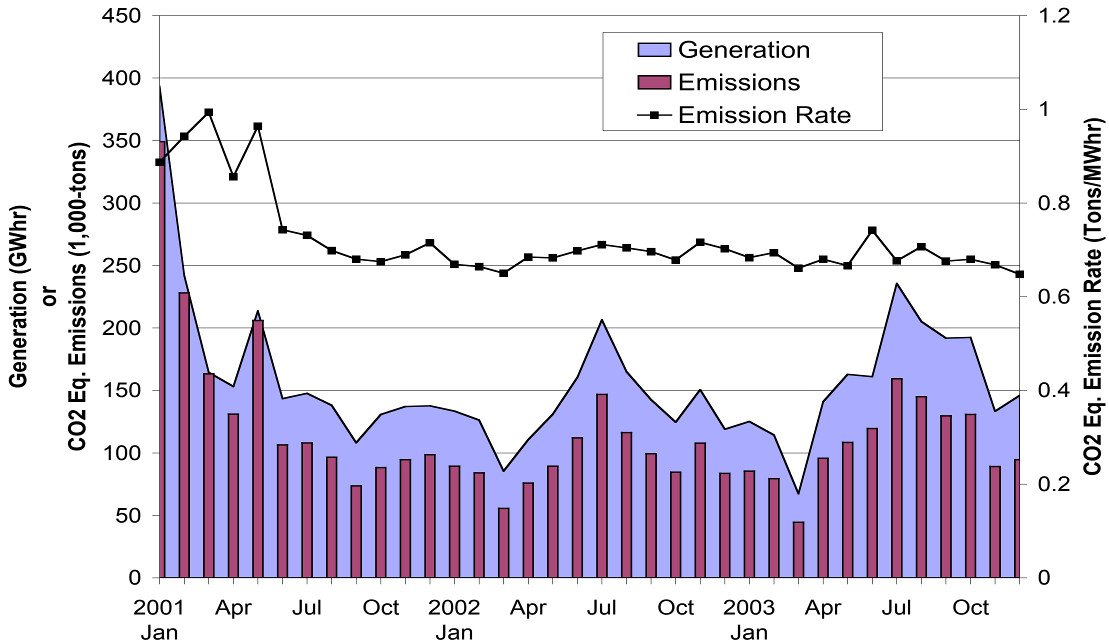


Figure 34 2001 to 2003 Simple Cycle Peaking Combustion Turbines CO_2 (million tons per month) and Emission Factor (tons/MWhr)



- **Finding:** The simple cycle peaking combustion turbine generation oxides of nitrogen average emission factors are approximately equivalent to the system averages.

- **Finding:** The simple cycle peaking combustion turbine generation particulate matter average emission factors are approximately equivalent to the system averages.

- **Finding:** The simple cycle peaking combustion turbine generation carbon dioxide-equivalent average emission factors are approximately equivalent to the system averages.

Internal Combustion Engines

Figure 35 2001 to 2003 Internal Combustion Engines NOx (tons per month) and Emission Factor (lbs/MWhr)

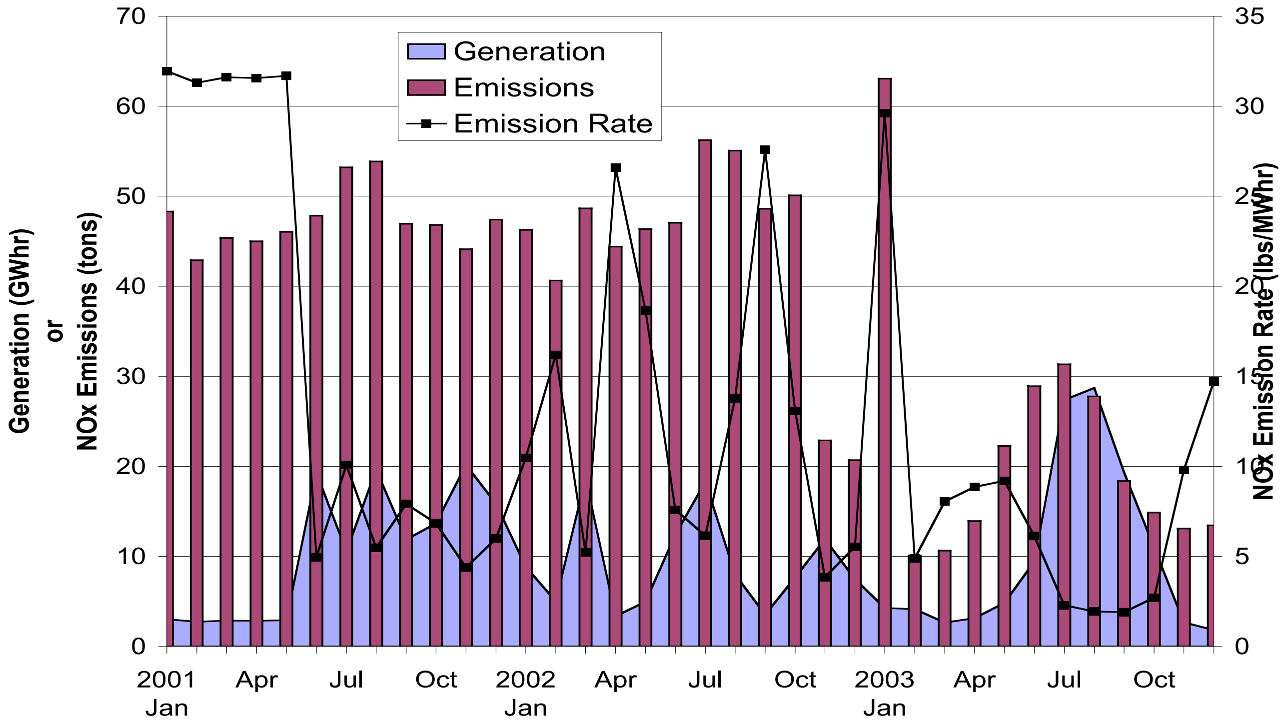


Figure 36 2001 to 2003 Internal Combustion Engines PM10 (tons per month) and Emission Factor (lbs/MWhr)

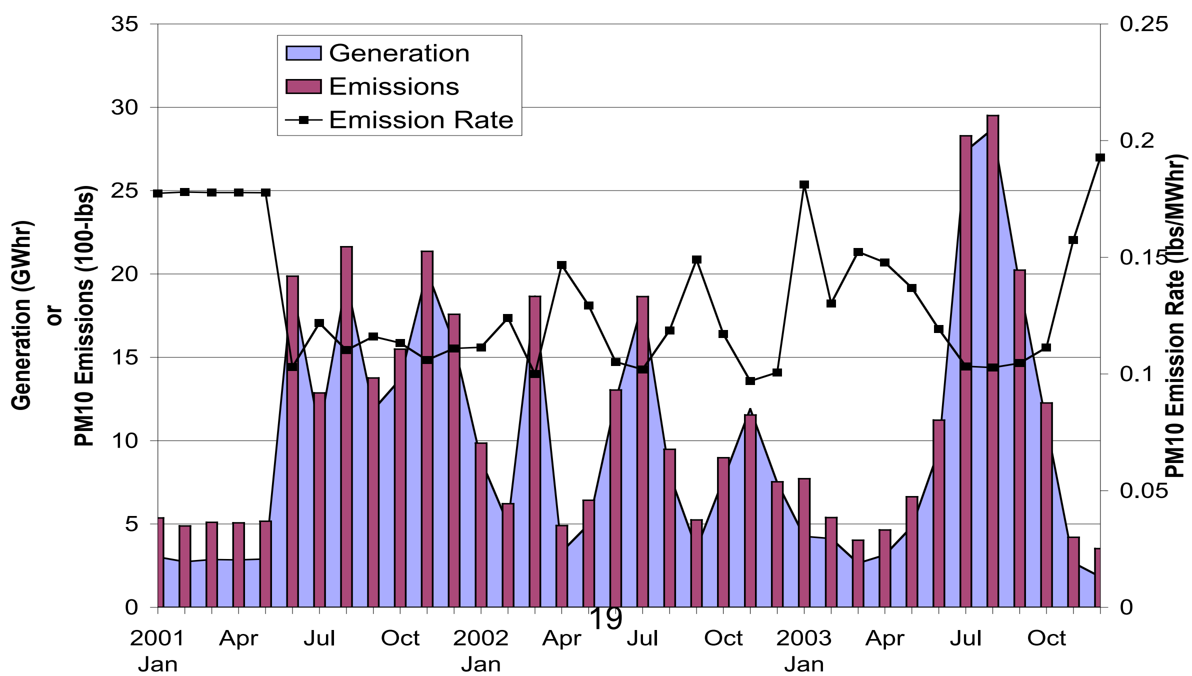
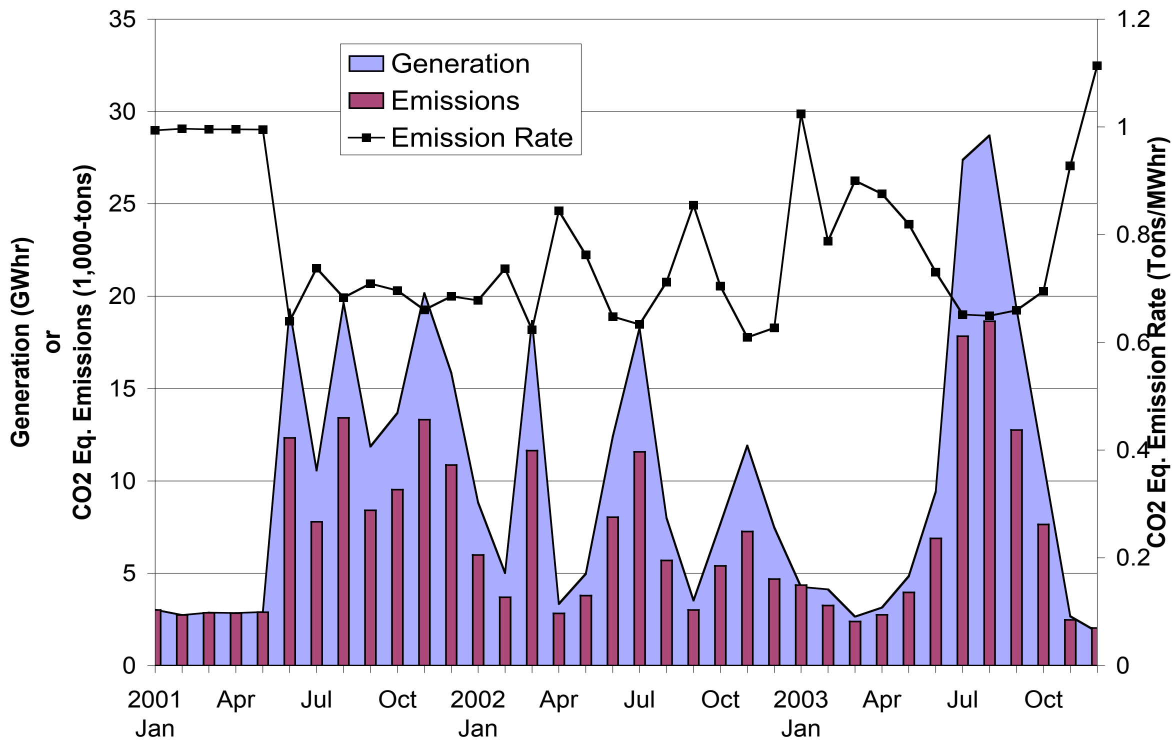


Figure 37 2001 to 2003 Internal Combustion Engines CO_2 (million tons per month) and Emission Factor (tons/MWhr)



Note that these figures and curves are derived from data from only four internal combustion engine generation units and may not be representative of the actual fleet operating instate.

- **Finding:** The internal combustion engine oxides of nitrogen average emission factors are much higher than the system averages.

- **Finding:** The internal combustion engine particulate matter average emission factors are approximately equivalent to the system averages.

- **Finding:** The cogeneration carbon dioxide-equivalent average emission factors are slightly higher than the system averages.

Waste to Energy Generation

Many waste to energy facilities use lower quality fuels such as biomass, waste, shredded tires and petroleum coke, which are more difficult to combust efficiently and cleanly. However, switching to cleaner fuels such as natural gas may cause these waste materials to be disposed up by other means that may have more significant environmentally effects than the emission rates seen below. The overall amount of generation from waste to energy is small.

Figure 38 2001 to 2003 Waste to Energy Generation NOx (tons per month) and Emission Factor (lbs/MWhr)

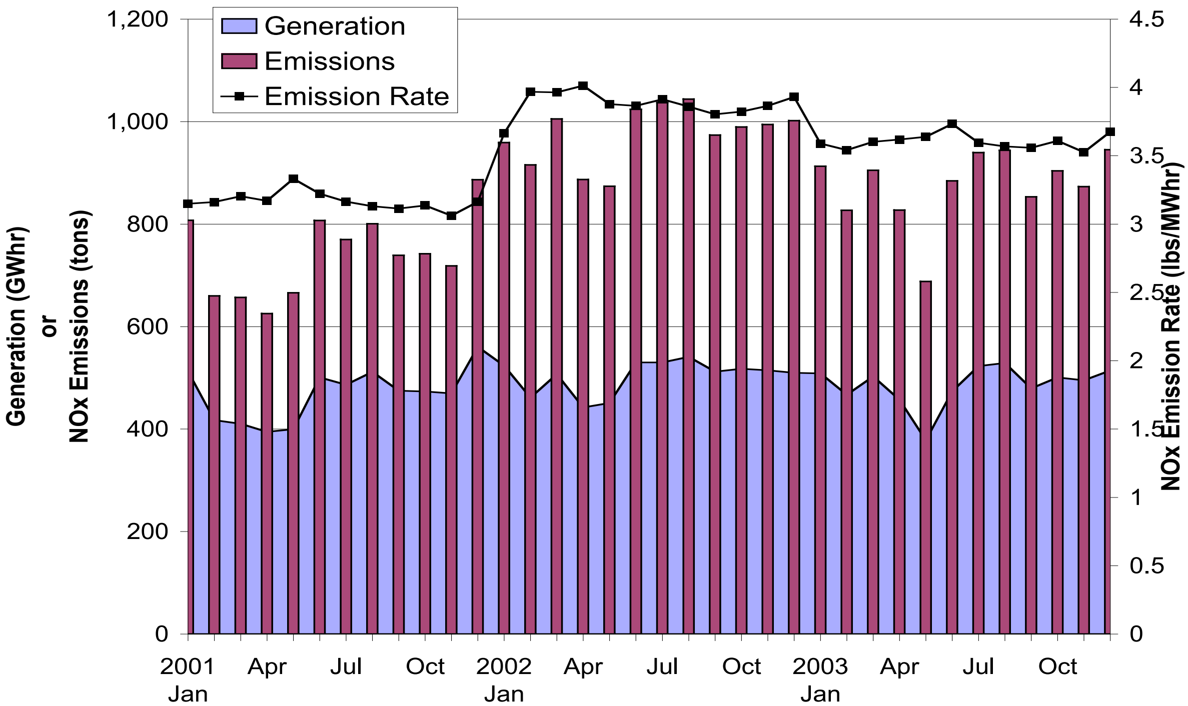


Figure 39 2001 to 2003 Waste to Energy Generation PM10 (tons per month) and Emission Factor (lbs/MWhr)

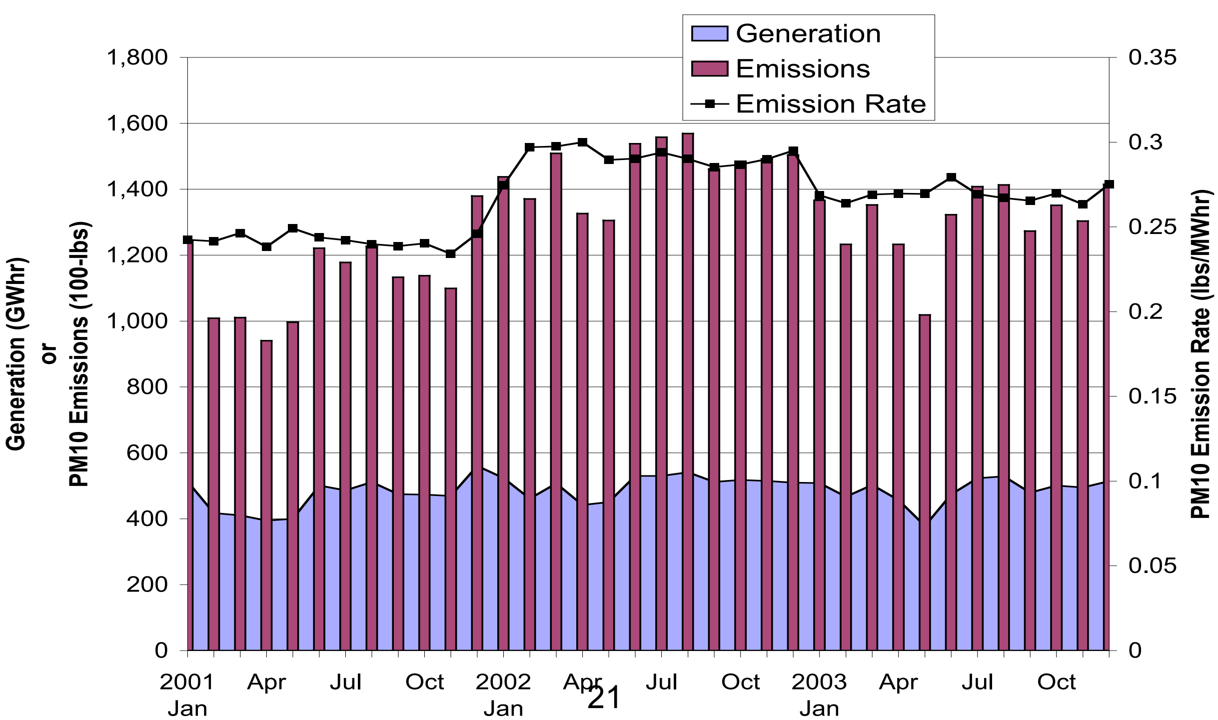
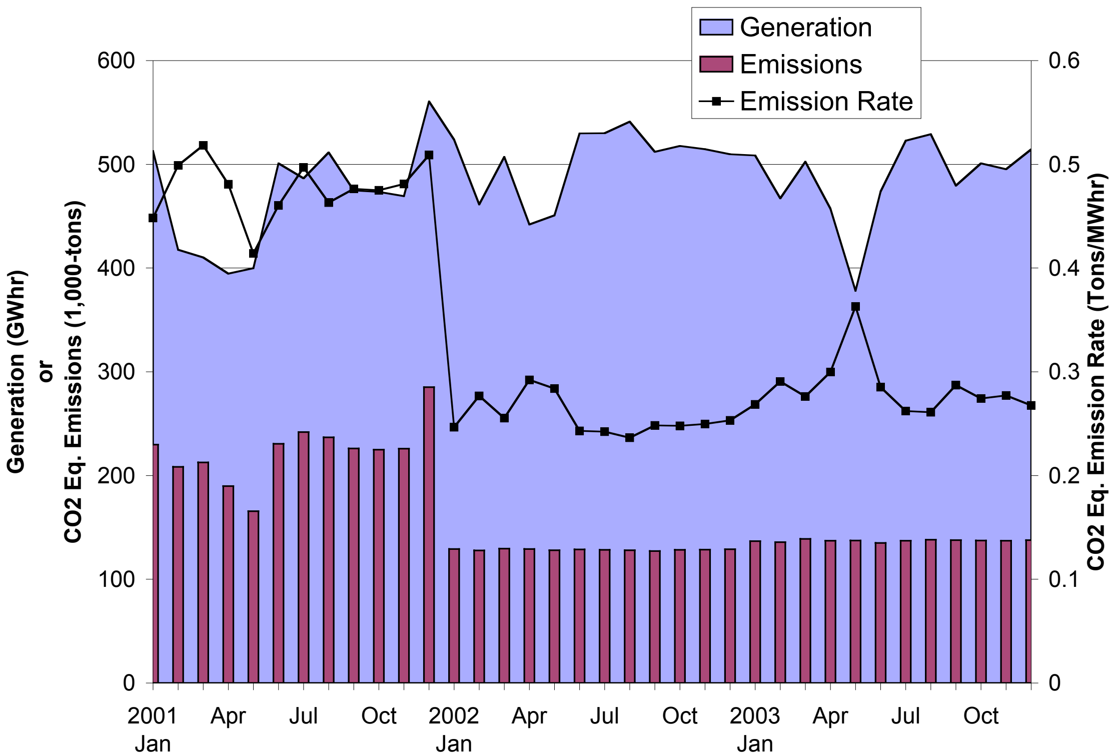


Figure 40 2001 to 2003 Waste to Energy Generation CO_2 (million tons per month) and Emission Factor (tons/MWhr)



- **Finding:** The waste to energy oxides of nitrogen average emission factors are much higher than the system averages.
- **Finding:** The waste to energy particulate matter average emission factors are approximately equivalent to the system averages.
- **Finding:** The waste to energy dioxide-equivalent average emission factors are higher than the system averages.

Solar Assisted Generation

Figure 42 2001 to 2003 Solar Assisted Generation NOx (tons per month) and Emission Factor (lbs/MWhr)

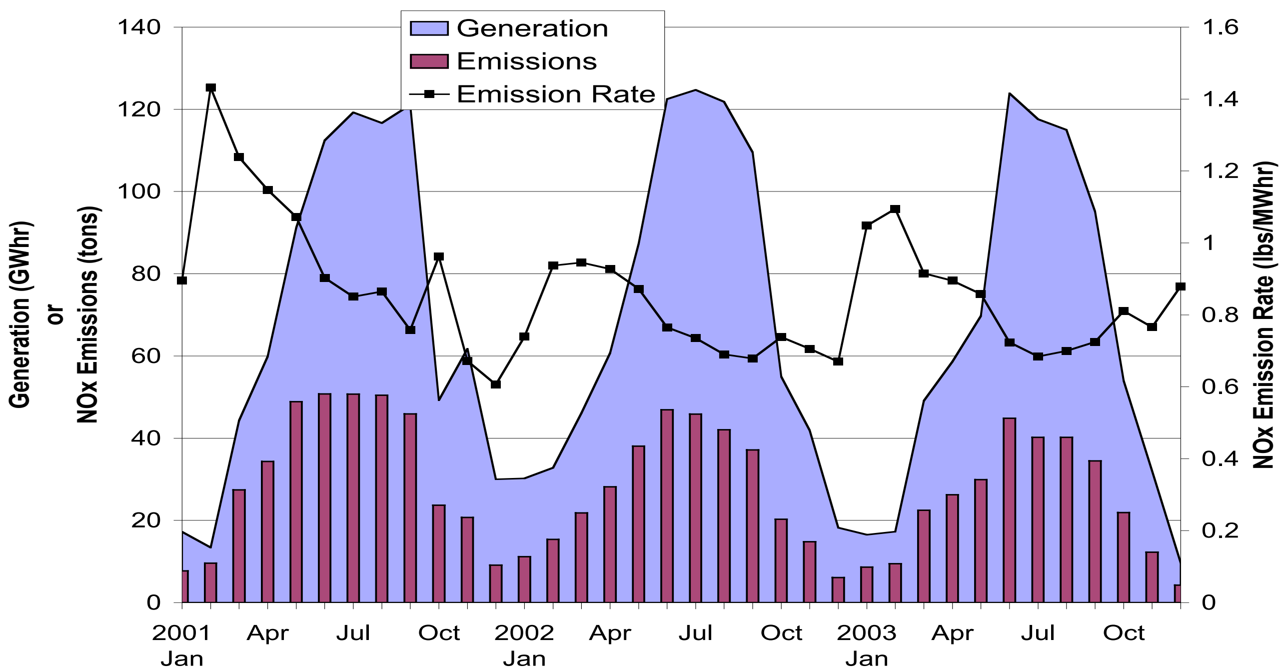


Figure 43 2001 to 2003 solar Assisted Generation PM10 (tons per month) and Emission Factor (lbs/MWhr)

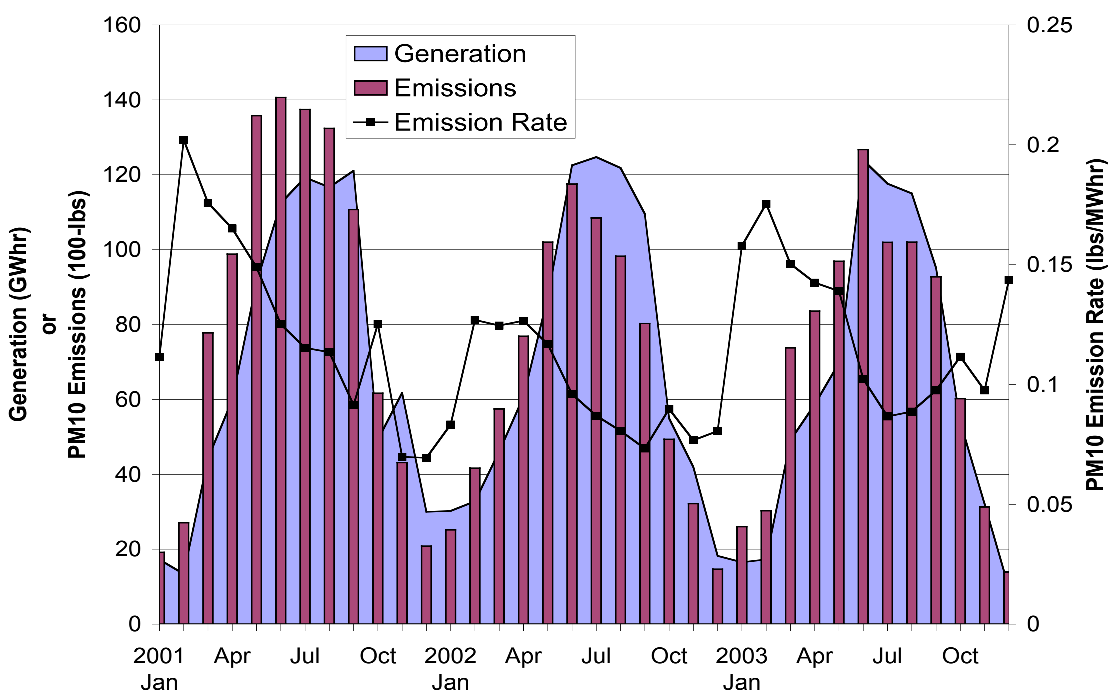
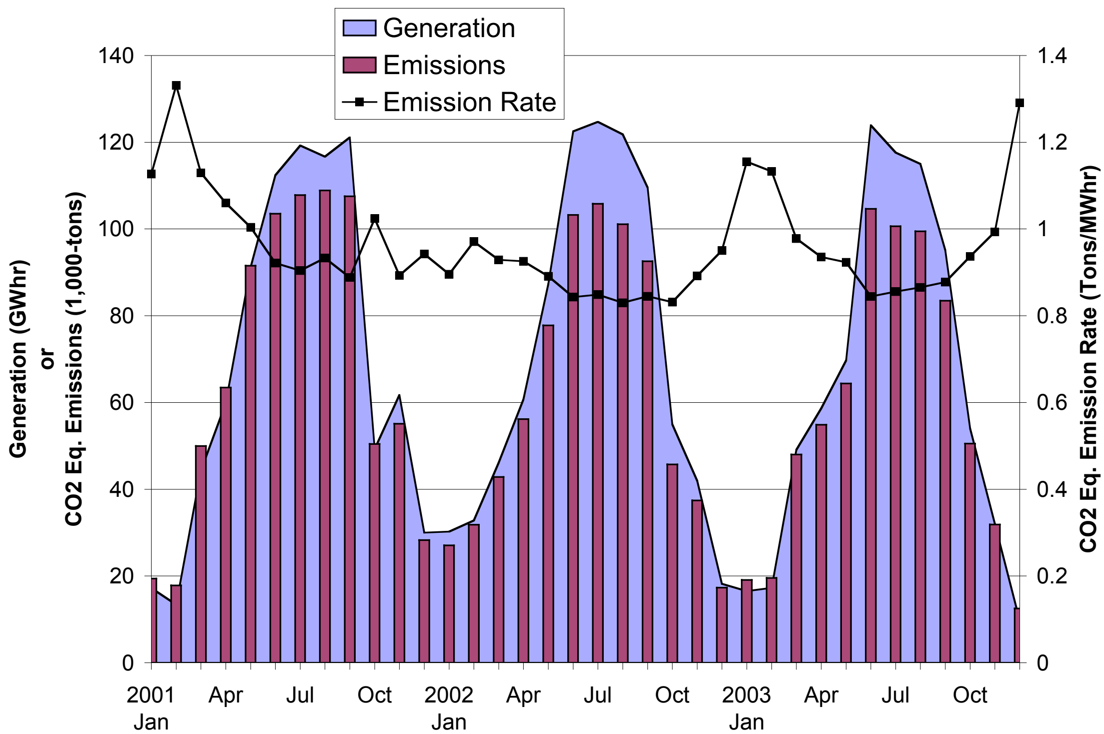


Figure 44 2001 to 2003 Solar Assisted Generation CO_2 (million tons per month) and Emission Factor (tons/MWhr)



- **Finding:** The solar assisted oxides of nitrogen average emission factors are much higher than the system averages.

- **Finding:** The solar assisted generation particulate matter average emission factors are approximately equivalent to the system averages.

- **Finding:** The solar assisted generation carbon dioxide-equivalent average emission factors are higher than the system averages.

Summary of Air Emission Trends

California's relatively poor air quality is the result of complex interactions of climate, topography, and air pollutant emissions. Improvements in the state's air quality are dependent on the state's ability to control and reduce air pollutant emissions. California regulators, consumers, and businesses have cooperated to achieve steady progress in most regions. While progress is being made, in some regions it has slowed or stalled. Districts are responding with new rules and regulations but often have had to delay the attainment date, resulting in continued exposure of the local residents to bad air quality.

Twenty-five years ago, one of the first targets of air quality regulators was the electricity generation sector. Since then, air pollutant emission reductions have been realized with increased reliance on natural gas and installation of emissions controls on most of the fossil-fueled generation resources. Also, California relies on a mix of nuclear and variable imported and hydroelectric power, which cause essentially no air quality impacts in California. California currently has an extremely low-emitting generation system.

For the existing in-state generation system, most technologies have similar particulate emission factors except where lower quality solid fuels are used. However, switching to cleaner fuels such as natural gas may cause these waste materials to be disposed up by other means that may have more significant environmentally effects than the emission rates seen below. The overall amount of generation from waste to energy is small, so any particulate matter benefits would be small.

Modern combined cycles, peakers, and retrofit steam boilers are at or below the system averages for oxide of nitrogen and carbon dioxide-equivalent emissions.

Solar assisted generation, as configured in California, is more polluting than most other resources available in-state.

Regardless, air pollutant emission reductions from the generation sector are likely to be a valuable, but minor, component of the continued air quality improvements as cleaner generation technologies, including emissionless renewables and energy efficiency programs, continue to be deployed and air quality rules are revised and implemented.

APPENDIX B: 2005 EPR METHODOLOGY FOR IN-STATE POWER PLANT AIR EMISSIONS ANALYSIS

The Development of the 2001-2003 In-State Power Plant Air Emissions Database

Introduction

The analysis for the In-State Power Plant Air Emissions for the 2005 Environmental Performance Report is intended to provide data and generally lend support to the IEPR. This effort has been broken into two separate analyses; 1996-2000 and 2001-2003 because they are based on two separate data sources. The 1996-2000 analysis is based on the E-GRID database system, while the 2001-2003 analysis is based on the CEC QFER database system. Linking these two systems is problematic at best, therefore staff will present them together without linking them. The total In-State Power Plant Air Emissions analysis is intended to both stand-alone and to be used in conjunction with the Out-of-State Power Plant Air Emissions analysis (presented in a separate report). This report is intended to document the development of the 2001-2003 In-State Power Plant Air Emissions Analysis. The 1996-2000 analysis will be presented in a separate report.

Basic Requirements

The intent of the 2001-2003 analysis is to show, in detail, the air emissions associated with the generation of electricity within the boarders of the State of California. The staff of the Environmental Office (EO) of the System Assessment and Facility Siting Assessment of the California Energy Commission was given the task of determining the most appropriate emission factors to use for each facility analyzed. There are approximately 1,000 electricity generating facilities within California, and typically one to six units at each facility. The Electricity Assessments Office (EAO), of the same division and department, provided generation and fuel use data (as well as other relevant identification information) for each unit at each facility on a monthly basis. This resulted in a database that was over 45,000 records long.

Reporting is required for county, air district, air basin and state totals by month for each year with supporting graphs for the trends discussion as necessary. Parameters to be reported include capacity, generation, fuel use, total emissions, emission factors (unit mass per unit energy input) and emission rates (unit mass per unit generation). Summary categories are far more general, but may include type of dispatch, type of fuel, type of technology and level of emission factor.

emission factors

The 2001-2003 In-State Power Plant Air Emissions analysis is based on monthly electricity generation and fuel use data from the QFER files EAO Staff and fuel based emission factors developed by EO Staff. While endeavors have been made to incorporate the recent EPR Forms database, significant disparity between units identification within the QFER database remains as a major hindrance to that effort.

The emission factors are first taken from the EPR Forms, then generally taken from the E-GRID database system and finally from the EPA AP-42 Emission Factor Compendium. The emissions factors are for the emissions of nitrogen oxides (NOx), sulfur oxides (SOx), carbon monoxide (CO), particulate less than 10 micrometers in diameter (PM10), non-methane total organic compounds (NMTOC), carbon dioxide (CO2), mercury (Hg), lead (Pb) and methane (CH4).
Since the E-GRID emission factors are expressed as facility average emission factors, they are sometimes not appropriate to represent specific units within a facility. Thus, the E-GRID emission factors could not simply be deferred to in the absence of the EPR Forms data. EO Staff determined a reasonable range for each technology type and specifically evaluated those E-GRID emission factors that fell outside of that range. If the E-GRID emission factor was available and acceptable it was used in the absence of the EPR Forms data. In a few specific cases EO Staff determined that the emission factor was not representative of the unit.

If an adequate E-GRID emission factor could not be found, EO Staff used the AP-42 Emission Factor Compendium to determine an appropriate emission factor. However several exception were made for NOx emissions, since California has implemented very stringent emission controls. For natural gas fired IC engines, boilers and turbines, EO Staff assumes wide spread emission controls are in effect. While these emission controls are clearly not all controlling the NOx emission to 2 ppm (current Best Available Control Standards), EO Staff feels that it is reasonable to assume that boiler and IC engines generally attain 10 ppm while turbines attain 3 ppm. The AP-42 emission factors used are shown Table A-1 (see appendix).

Significant efforts were made by EO staff to validate the NOx, CO2 eq and PM10 emission totals with existing emission inventories. While not a perfect match, EO staff is confident that the results show that the emission estimates presented are reasonably representative for the facilities in question. However, the CO, NMTOC, SO2, Pb and Hg emissions were not as aggressively pursued and as a result are not fit to report.

CO2 Emission Factors

CO2 emission factors can be generated in one of two ways. They can be measured via an in-stack CO2 monitor (typically large coal fired stations do this) or they are calculated from the assumed carbon in the fuel. The latter is the far more typically method in California. Where the data was available from EPR Forms or E-GRID (i.e., in-stack monitoring), EO staff included it if it was reasonably close to the calculated CO2 emission factor. The rest of the CO2 emission factors were calculated based on the fuel type and carbon content in accordance with the International Panel on Climate Change (IPCC) Greenhouse Gas Inventory Requirements.

EO staff determined the methane (CH4) and nitric oxide (N2O) emissions, as well as the CO2 emission factors for each fuel type. EO staff combined these emissions into CO_2 equivalent emissions via their global warming potential (GWP). The GWP of each greenhouse gas is the effect that the gas has on global warming in comparison to the effect of CO_2 on global warming. So, for example the GWP of CO_2 is 1.0, for CH_4 the GWP is 21 and for N_2O the GWP is 310. That means that every pound of CO_2 is equivalent to 1 pound of CO_2, while every pound of N_2O is equivalent to 310 lbs of CO_2. In the reports generated for the IEPR, EO staff does not show the specific contributions of the CH_4 and N_2O, but only reports the total CO_2 equivalent of CO_2, CH_4 and N_2O.

For the special case landfill gas as fuel for the production of electricity, EO staff had to make several assumptions. Landfill gas, is comprised of primarily of CH_4 and CO_2 (with other trace elements). However, the Btu value of landfill gas is derived entirely from the CH_4 in the gas. So, an emission factor based only on the CH_4 component would be acceptable except for the CO_2 component already in the fuel. In order to develop an appropriate CO_2 emission factor for landfill gas, it is necessary to convert the volume of Landfill gas into masses of CO_2 and CH_4, then convert the CH_4 (by combustion) into CO_2 and sum the results. In doing this, EO staff took into consideration that the volume percentage of CH_4 in the landfill gas varies (from about 25% to 60%). EO staff determined that landfill gas should have an average of 270 lbs CO_2/mmBtu (EO staff purposefully restricted this result to two significant figures). These calculations are presented in the Attachment. If further refinement of the CO_2 emissions of Landfill gas to energy is deemed necessary, staff recommends individual emission factors based on the specific landfill gas annual average energy content.

CO_2 emissions from the combustion of wood and other qualified biomass products are presumed by IPCC convention to be zero, however there are several such facilities that also burn non-qualifying fuels. In these cases, if the amount of fuel is known or estimated, a CO_2, CH_4 and N_2O emission factor was derived and applied for it and the CO_2 Equivalent emissions were calculated.

EO staff calculated all CO_2 emission factors with the International Panel on Climate Change (IPCC) methodologies and assumptions. The carbon content coefficients for fuel combustion used by the IPCC is reproduced in the Attachment.

Emission Factors Calculated from AP-42

For the rest of the emission factors developed, EO staff used the information found in the EPA AP-42 compendium. All PM10, CO, NMTOC, N_2O and Pb emission factors were developed from this source. Also, most of the Hg emission factors were also developed from AP-42, however some were found in E-GRID. EO staff disaggregated the emission factors by fuel type and prime mover.

Biomass

Biomass came in two fuel types that were not well defined, one EO staff labeled Biomass-nonwood, the other Biomass-Waste. For the purpose of determining emission factors, EO staff assumed that the Biomass-nonwood fuel type was best represented by “wet wood” in the AP-42 definitions. However, the Biomass-Waste fuel type EO staff initially categorized as waste combustion, but finally determined that it also was best represented by wet wood.

Coal

EO staff assumed that all coal fired power plants in the western grid use pulverized coal with eight-percent ash content and a fuel content of 23.89 mmBtu/Ton.

Distillate

Distillate, or fuel oil number 2 (FO2) was broken down into two categories, internal combustion engines (FO2-IC) and turbines (FO2-T). EO staff found no methane emission rate for FO2-IC and assumed that it was reasonably equal to the methane emission found for FO2-T. EO staff found no NMTOC emission rate for FO2-T and assumed that it was equal to the emission rate found for FO2-IC. EO staff found no N2O emission rate for FO2-IC and assumed that it was equal to the emission rate found for FO2-T. Finally, EO staff could only find an emission rate for Hg for FO6-T (below) and assumed that FO2-T and FO2-IC were equal to FO6-T. EO staff assumed that the energy content of FO2 is 138.69 mmBtu/1000gallons.

Residual

Residual, or fuel oil number 6 (FO6) was to be broken down into IC and T, however only a turbine type was found in the data provided by EAO. EO staff assumed a utility boiler operation would be roughly equivalent to the emissions from a turbine operation firing FO6 and that the energy content of FO6 is 149.69 mmBtu/1000gallons.

Jet Fuel

EO staff assumed that the jet fuel would be fired in a turbine and used the emission factors found in AP-42. EO staff did not find CH4 or N2O emission factors for jet fuel in AP-42 and assumes that they are equal to the emission factor found for FO2-T.

Natural Gas

EO staff broke natural gas into three categories, boilers (NG-B), NG-IC and NG-T. EO staff did not find a PM10 emission for NG-T and assumes it is equal to NG-IC. EO staff found CH4, N20, Pb and Hg emission factors only for NG-B and assumes that the emission factors for NG-T and NG-IC are the same.

Landfill Gas

Staff found no useful information on landfill gas emission factors and assumes that they are equal to natural gas emission factors. Thus the emission factors for LFG-IC are equal to the emission factors for NG-IC and the emission factors for LFG-T and equal to the emission factors for NG-T. EO staff assumes that NG has an energy content of 1030 mmBtu/mmCF.

Solar Assisted

EO staff found several instances of solar assisted boiler and turbine systems. EO staff assumes that these emission factors are equal to the emission factors for NG-B and NG-T.

Waste Heat Turbines

EO Staff presumes that an fuel fired for the purpose of driving a waste heat turbine is natural gas and all emission factors associated with it are equal to the emission factors for NG-T.

Wood

EO staff assumes all wood burning boiler units to be "dry wood" as defined in the AP-42 compendium.

Non-Emitting Units

EO staff assumes zero emission for the following generating unit for all pollutant: Geothermals (due to a lack of consistent data), nuclear, PV solar and wind.

Generation and Fuel Use Data

The generation and fuel use data was provided to EO Staff by EAO Staff from the QFER database system. The data was disaggregated to the individual unit level and included the three years 2001 through 2003. The data showed gross and net generation (totals for the year) as well as net generation for each month. The data included both primary and secondary fuel use data for each month as well as the type of fuel being burned.

A cursory review of the data revealed no significant problem or issues. However, after applying the appropriate emission factors to the QFER data, EO Staff determined that there were a number of errors that where causing significant problems. Approximately 10% of the generation and fuel use data provided were erroneous. While they did not represent a large source of emission or generation, this 10% was having significant effect of the calculated emission rates for various regions and categories. After discussing the mater with EAO Staff, it was agreed that EO Staff would correct the erroneous data as necessary.

In order to perform this task, EO Staff calculated the heatrate for each unit on a monthly basis. The heatrate is a measure of the unit efficiency; it is measured in units of input energy per unit of generation (most commonly Btu/kWh). Alternatively, it can be determined by dividing 3413 Btu/kWh (a standard conversion) by the thermal efficiency of the unit. For example a unit might have an efficiency of 34% which corresponds to a heatrate of 10,038 btu/kwh.

After calculating the heatrate of each unit for each month of data, EO Staff compared it to a range of what it considers reasonable heatrates. This range represents efficiencies no less than 10% and no greater than 40%. Initially, more than 6,000 records lay outside this range (about 13% of the records). After further investigation, EO Staff found that most of the 6,000 records were legitimate. After raising the upper limit from 40% to 60% efficiency, EO Staff determined that the remaining records (approximately 4,000 or 9%) were most likely erroneous and required further investigation.

EO Staff found that a significant number of records recorded power generation on a particular month, with no corresponding fuel use. For these records, EO Staff determined the appropriate heatrate to use and replaced the fuel use value accordingly. Determining the heatrate required the investigation of the other records for the unit in question and the investigating into any information from the E-GRID system. These corrections were relatively simple, but time consuming.

The remaining records (approximately 2,000 or 5%) required further investigation. Each record was investigated to determine the nature of the problem and a likely solution. The problems ranged from simple typographical errors to complex fuel use reporting errors. EO Staff chose to leave some suspicious data unmodified due to clear extenuating circumstances. For example, a unit may have a low electricity generation value and a relatively high fuel use value in the same month resulting in a high heatrate. However, this may be the result of cogeneration operation or a significant number of startups within a month. If this were an investigation into a single month, EO Staff would be inclined to leave the values unchanged. The resolution of these 2,000 records constituted the bulk of EO Staff's time and efforts in this matter.

Facility locations

EO staff has found that several of the facility locations are not correct within the database. Primarily, this problem arises at the Air District and Air Basin level, but the county level seems to be correct.

Conclusions

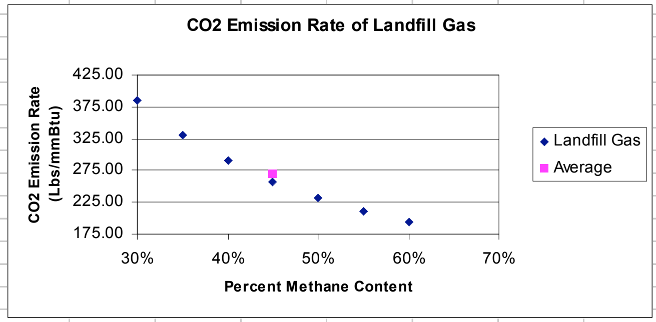
EO staff concludes that there are significant deficiencies with the results presented here based on the data availability, and the assumptions that were made. However, these results are reasonably representative of the trends of generation and resulting emissions. For trends within the air basin or air district, EO staff strongly recommends that the reader deferred to the California Air Resources Board or the local air district.

APPENDICES

TABLE A-1
Default Emission Factors (primarily based on AP-42)

	Emission Factors (lbs/mmBtu except as noted)											Water Use
Fuel/Tech Description	**NOx**	**NOx ppm**	**SOx**	**CO**	**PM10**	**CO2**	**CH4**	**NMTOC**	**N2O**	**Pb**	**Hg**	**(gal/kWhr)**
Biomass, non-wood	0.2200	54.0911	0.0250	0.6000	0.2900	300	0.0210000	0.0390000	0.0130000	0.0000480	0.0000035	0.50
Biomass, waste	0.2200	54.0911	0.0250	0.6000	0.2900	300	0.0210000	0.0390000	0.0130000	0.0000480	0.0000035	0.50
Coal	0.2846	68.6901	0.8077	0.0209	0.7702	203	0.0016743	0.0025115	0.0037673	0.0005070	0.0000160	0.50
Distillate, IC engine	0.0714	18.2859	1.1214	0.0033	0.0144	159	0.0020189	0.0004100	0.0007931	0.0000140	0.0000320	0.00
Distillate, Turbine	0.0714	18.2859	1.1214	0.9373	0.3064	159	0.0020189	0.0004100	0.0007931	0.0000140	0.0000320	0.00
Residual, turbine	0.1733	44.4702	4.1867	0.0334	0.0668	167	0.0018705	0.5077143	0.0007348	0.0001940	0.0000320	0.50
Geothermal	0.0000		0.0000	0.0000	0.0000	0	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.25
Interuptable load (modeling only)	0.0000		0.0000	0.0000	0.0000	0	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.00
Jet fuel, Turbine	0.0714	18.3456	0.2900	0.9500	0.3100	145.2	0.0020189	0.0040000	0.0007931	0.0000140	0.0000320	0.25
Landfill gas, IC	0.2350	63.6831	0.0006	0.3874	0.0097	270	0.0022330	0.1126214	0.0021359	0.0000005	0.0000003	0.00
LFG, Turbine	0.0590	16.0000	0.0006	0.0820	0.0097	270	0.0022330	0.0021000	0.0021359	0.0000005	0.0000003	0.25
Natural Gas, Boiler	0.0369	10.0000	0.0006	0.0816	0.0018	118	0.0022330	0.0053398	0.0021359	0.0000005	0.0000003	0.50
Natural Gas, IC	0.0369	10.0000	0.0006	0.3874	0.0097	118	0.0022330	0.1126214	0.0021359	0.0000005	0.0000003	0.00
Natural Gas, T	0.0111	3.0000	0.0006	0.0820	0.0097	118	0.0022330	0.0021000	0.0021359	0.0000005	0.0000003	0.25
Nuclear	0.0000		0.0000	0.0000	0.0000	0	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.50
Solar	0.0000		0.0000	0.0000	0.0000	0	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.00
Solar, Boiler	0.1235	33.4755	0.0006	0.0816	0.0018	118	0.0022330	0.0053398	0.0021359	0.0000005	0.0000003	0.50
Solar, Turbine	0.2448	66.3388	0.0006	0.0820	0.0097	118	0.0022330	0.0021000	0.0021359	0.0000005	0.0000003	0.25
Waste heat, turbine	0.2448	66.3388	0.0006	0.0820	0.0097	118	0.0022330	0.0021000	0.0021359	0.0000005	0.0000003	0.25
Wind	0.0000		0.0000	0.0000	0.0000	0	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.00
Wood fired boiler	0.4900	125.1695	0.0250	0.6000	0.4000	300	0.0210000	0.0390000	0.0130000	0.0000480	0.0000035	0.50

CO2 Emission Rates for Landfill Gas



Combusted Methane	116.38	Lbs CO2 per mmBtu
CO2	0.117	Lbs/CF
CH4	1013	Btu/CF

	Percent Methane of Landfill Gas	CO2 Emission Rate of Landfill Gas (lbs CO2 per mmBtu)		
	30%	385.88		
	35%	330.88		
	40%	289.63		
	45%	257.54		
	50%	231.88		
	55%	210.88		
	60%	193.38		
Average	**45%**	**271.44**	**270**	**rounded to 2 sig. fig.**

Carbon Content Coefficients for Fuel Combustion

	Lbs C /mmBtu		Oxidation Factor	CO2/C	Lbs CO2/mmBtu
Asphalt and Road Oil	45.5		0.99		165.17
Ethanol	41.6		0.99		151.01
Distillate Fuel Oil	44		0.99		159.72
Jet Fuel	43.5		0.99		157.91
Kerosene	43.5		0.99		157.91
LPG	37.8		0.99		137.21
Lubricants	44.6		0.99		161.90
Motor Gasoline	42.8		0.99		155.36
Residual Fuel Oil	47.4		0.99		172.06
Mics. Petroleum Products and Crude Oil	44.7		0.99		162.26
Naphtha	40		0.99		145.20
Other Oil	44		0.99		159.72
Pentanes Plus	40.2		0.99	**3.666667**	145.93
Petrochemical Feed	42.7		0.99		155.00
Petroleum Coke	61.4		0.99		222.88
Still Gas	38.6		0.99		140.12
Special Naphtha	43.8		0.99		158.99
Unfinished Oils	44.6		0.99		161.90
Waxes	43.7		0.99		158.63
Anthracite Coal	62.1		0.99		225.42
Bituminous Coal	56		0.99		203.28
Sub-Bituminous Coal	57.9		0.99		210.18
Lignite Coal	58.7		0.99		213.08
Natural Gas	31.9		**0.995**		116.38
Wood	0.475	**% of Carbon in Fuel**	**0.9**		
Ethanol	41.8		0.99		151.73

Data found in EPA AP-42

	AP-42 Emission Factors									GCC Workbook	
	CO	**PM10**	**CH4**	**NMTOC**	**N2O**	**Units**	**Pb**	**Hg**	**Units**	**Fuel Content**	**Units**
Bio	0.6	0.29	2.10E-02	0.039	0.013	lbs/mmbtu	4.80E-05	3.50E-06	lbs/mmBtu		
Bio-Other											
Coal	0.5	18.4	0.04	0.06	0.09	Lbs/Ton	507	16	Lbs/1E12 * btu	23.89	mmBtu/Ton
FO2-IC	0.0033	0.01442		0.00041		lbs/mmbtu	0.000014				
FO2-T	130	42.5	0.28	76	0.11	lbs/1000 gal				138.6904762	mmBtu/1000 gal
FO6-T	5	10	0.28	76	0.11	lbs/1000 gal	194	32	Lbs/1E12 * btu	149.6904762	mmBtu/1000 gal
Geo	0	0	0	0	0	0	0	0	0		
intload	0	0	0	0	0		0	0			
Jet-T	0.95	0.31		4.00E-03		Lbs/mmBtu	1.40E-05		Lbs/mmBtu		
LFG-IC											
LFG-T											
NG-B	84	1.9	2.3	5.5	2.2	Lbs/mmcf	0.0005	2.60E-04	Lbs/mmcf	1030	mmBtu/mmcf
NG-IC	399	10		116		Lbs/mmcf				1030	mmBtu/mmcf
NG-T	0.082			0.0021		lbs/mmbtu					
Nuc	0	0	0	0	0		0	0			
Sun	0	0	0	0	0		0	0			
Sun-B											
Sun-T											
WH-T											
Wind	0	0	0	0	0		0	0			
Wood	0.6	0.4	2.10E-02	0.039	0.013	lbs/mmBtu	4.80E-05	3.50E-06	lbs/mmBtu		

Emission Factors Developed from EPA AP-42 Data

	Emission Factors (lbs/mmBtu)						
	CO	**PM10**	**CH4**	**NMTOC**	**N2O**	**Pb**	**Hg**
Bio	6.00E-01	2.90E-01	2.10E-02	3.90E-02	1.30E-02	4.80E-05	3.50E-06
Bio-Other	6.00E-01	2.90E-01	2.10E-02	3.90E-02	1.30E-02	4.80E-05	3.50E-06
Coal	2.09E-02	7.70E-01	1.67E-03	2.51E-03	3.77E-03	5.07E-04	1.60E-05
FO2-IC	3.30E-03	1.44E-02	2.02E-03	4.10E-04	7.93E-04	1.40E-05	3.20E-05
FO2-T	9.37E-01	3.06E-01	2.02E-03	4.10E-04	7.93E-04	1.40E-05	3.20E-05
FO6-T	3.34E-02	6.68E-02	1.87E-03	5.08E-01	7.35E-04	1.94E-04	3.20E-05
Geo	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
intload	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Jet-T	9.50E-01	3.10E-01	2.02E-03	4.00E-03	7.93E-04	1.40E-05	3.20E-05
LFG-IC	3.87E-01	9.71E-03	2.23E-03	1.13E-01	2.14E-03	4.85E-07	2.52E-07
LFG-T	8.20E-02	9.71E-03	2.23E-03	2.10E-03	2.14E-03	4.85E-07	2.52E-07
NG-B	8.16E-02	1.84E-03	2.23E-03	5.34E-03	2.14E-03	4.85E-07	2.52E-07
NG-IC	3.87E-01	9.71E-03	2.23E-03	1.13E-01	2.14E-03	4.85E-07	2.52E-07
NG-T	8.20E-02	9.71E-03	2.23E-03	2.10E-03	2.14E-03	4.85E-07	2.52E-07
Nuc	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Sun	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Sun-B	8.16E-02	1.84E-03	2.23E-03	5.34E-03	2.14E-03	4.85E-07	2.52E-07
Sun-T	8.20E-02	9.71E-03	2.23E-03	2.10E-03	2.14E-03	4.85E-07	2.52E-07
WH-T	8.20E-02	9.71E-03	2.23E-03	2.10E-03	2.14E-03	4.85E-07	2.52E-07
Wind	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Wood	6.00E-01	4.00E-01	2.10E-02	3.90E-02	1.30E-02	4.80E-05	3.50E-06

Excel sheets go here

APPENDIX C: THERMAL ELECTRIC GENERATING FACILITIES LICENSED BY THE CALIFORNIA ENERGY COMMISSION IN 2003 AND 2004

Project	Local Jurisdiction	MW	Project Site Size (Acres)	Project-Site Setting Prior to Project Construction*	Project Converted Agricultural Land? (Yes/No)	Educational Facility Within 0.25-Mile Radius? (Yes/No)	Local Land Use Discretionary Action (i.e., general plan amendment or zoning change)?
Donald Von Raesfeld Power Plant (formerly Pico Power Project)	City of Santa Clara	147	2.86	Brownfield (Site within existing substation property)	No	No	Project allowed by city general plan and zone district.
Kings River Conservation District Peaking Power Plant (SPPE)**	County of Fresno	97	9.5	Intermediate	No	No	Site designated appropriately in general plan. Zoning allows power plants, subject to approval of a conditional use permit (CUP).
Magnolia Power Plant Project	City of Burbank	328	4	Brownfield (Site within existing Magnolia Power Station property)	No	No	Project allowed by city general plan and zone district. Energy Commission made findings for CUPs that would have been required for offsite laydown and parking areas and exhaust stack height allowance if the city had jurisdiction.

Project	Local Jurisdiction	MW	Project Site Size (Acres)	Project-Site Setting Prior to Project Construction*	Project Converted Agricultural Land? (Yes/No)	Educational Facility Within 0.25-Mile Radius? (Yes/No)	Local Land Use Discretionary Action (i.e., general plan amendment or zoning change)?
Malburg Generating Station	City of Vernon	134	3.4	Brownfield (Site within existing Station A power complex property)	No	No	Project allowed by city general plan and zone district.
Riverside Energy Resource Center (SPPE)	City of Riverside	96	8	Brownfield	No	No	Site designated appropriately in general plan. Zoning allows power plants, subject to approval of a CUP.
Walnut Energy Center	City of Turlock	250	18	Greenfield	Yes (Site used to grow crops)	No	Project allowed by city general plan and zone district.
MID Electric Generation Station – Ripon (SPPE)	City of Ripon	95	12.25	Greenfield	No	No	Project allowed by city general plan and zone district.
SMUD Cosumnes Power Plant Project, Phase 1	County of Sacramento	500	30	Greenfield (Site is within a 2,480-acre area owned by SMUD, and south of the Rancho Seco Nuclear Plant, in the process of being decommissioned)	Yes (Site grazed for weed control)	No	Project allowed by county general plan and zone district.
Palomar Energy Project	City of Escondido	546	20	Greenfield	No	No	Project allowed by city general plan, specific plan, and zone district.

Project	Local Jurisdiction	MW	Project Site Size (Acres)	Project-Site Setting Prior to Project Construction*	Project Converted Agricultural Land? (Yes/No)	Educational Facility Within 0.25-Mile Radius? (Yes/No)	Local Land Use Discretionary Action (i.e., general plan amendment or zoning change)?
Salton Sea Unit #6 Geothermal Power Plant	County of Imperial	185	80	Greenfield	Yes (96 acres, which includes the project site, geothermal well pad sites and associated above ground pipelines, of land classified as Prime Farmland and Farmland of Statewide Importance by the California Department of Conservation)	No	Site designated appropriately in general plan. Zoning allows power plants, subject to approval of a CUP. Commission Decision incorporates conditions of approval that would have been included in CUP if county had jurisdiction.
East Altamont Energy Center	County of Alameda	1,100	40	Greenfield	Yes (Site designated as Prime Farmland by the Department of Conservation)	No	Project allowed by county specific plan.

Project	Local Jurisdiction	MW	Project Site Size (Acres)	Project-Site Setting Prior to Project Construction*	Project Converted Agricultural Land? (Yes/No)	Educational Facility Within 0.25-Mile Radius? (Yes/No)	Local Land Use Discretionary Action (i.e., general plan amendment or zoning change)?
Inland Empire Energy Center	County of Riverside	670	35	Greenfield	Yes (26.6 acres of agricultural land classified as Farmland of Local Importance by the Department of Conservation)	Yes	Site designated appropriately in general plan. Zoning allows power plants, subject to approval of a CUP. Commission Decision incorporates conditions of approval that would have been included in CUP if county had jurisdiction.
San Joaquin Valley Energy Center	City of San Joaquin	1,087	25	Greenfield	Yes (Site used to grow cotton. Classified as Prime Farmland by the Department of Conservation)	No	Site designated appropriately in general plan. Zoning allows power plants, subject to approval of a special use permit. City adopted advisory resolutions containing recommended conditions and findings regarding height variance.
Morro Bay Modernization & Replacement Project	City of Morro Bay	1,200	14	Brownfield (Site within existing Morro Bay Power Plant property)	No	No	Project allowed by city general plan and zone district.

Project	Local Jurisdiction	MW	Project Site Size (Acres)	Project-Site Setting Prior to Project Construction*	Project Converted Agricultural Land? (Yes/No)	Educational Facility Within 0.25-Mile Radius? (Yes/No)	Local Land Use Discretionary Action (i.e., general plan amendment or zoning change)?
Tesla Power Plant Project	County of Alameda	1,120	25	Greenfield	Yes (Site subject to a Williamson Act contract. *** Used for cattle grazing)	No	Site designated appropriately in land use plan. Zoning allows power plants, subject to approval of a CUP. Commission Decision incorporates conditions of approval that would have been included in CUP if county had jurisdiction.
El Segundo Power Redevelopment Project	City of El Segundo	630	24.7	Brownfield (Site within existing El Segundo Generating Station property)	No	No	Project allowed by city local coastal plan and zone district.
Total at Build-Out		8,185 MW	351.71 acres		260.6 acres		

Project	Local Jurisdiction	MW	Project Site Size (Acres)	Project-Site Setting Prior to Project Construction*	Project Converted Agricultural Land? (Yes/No)	Educational Facility Within 0.25-Mile Radius? (Yes/No)	Local Land Use Discretionary Action (i.e., general plan amendment or zoning change)?

*** Project Setting Descriptions:**

Greenfield – Existing undisturbed site by humankind (virgin site). Agricultural crop producing land (e.g. row crops, vineyards, orchard), rangeland, forest, and open space land.
Intermediate – Existing moderately disturbed site. Moderately improved and developed site. Limited infrastructure. Existing mixed-land uses may surround site.
Brownfield – Existing or previous highly disturbed site. Existing improved and developed site. Blighted or distressed site. In-fill development project in an urban area. Infrastructure available.

** The Energy Commission may exempt a project not exceeding 100 MW in capacity from its licensing process if it finds that no substantial adverse impacts on the environment or on energy resources will result from the construction or the operation of the project. This process is known as the Small Power Plant Exemption (SPPE). The Commission is the lead agency under the California Environmental Quality Act for all projects that it licenses or exempts from the licensing process. However, projects exempted remain subject to applicable local permitting requirements, such as approval of a conditional use permit).

*** The Alameda County Board of Supervisors granted tentative approval of a partial cancellation of a Williamson Act Contract, applicable to 60 of 320 acres of contracted land, with the provision that the applicant dedicate 100 acres of the 260 acres remaining under contract as a permanent agricultural conservation easement. The county's approval is considered tentative because had the project not been certified, the partial cancellation would have been voided. In addition, the County may commence proceedings to withdraw the cancellation if the project owner does not begin construction of the Tesla Power Plant Project within five years of the tentative approval date.

[1] Order Adopting Environmental Data Forms and Instructions, California Energy Commission, December 17, 2004.

[2] For example, the database only includes four Internal Combustion Engine generation units. In fact, there are many more ICE units installed throughout the state, but represent a very; small portion of the instate capacity.

[3] Environmental Performance Report of California's Electric Generation Facilities California Energy Commission Publication # 700-01-001 Released: July 2001 http://www.energy.ca.gov/reports/2001-11-20_700-01-001.html

[4] 2003 Environmental Performance Report. California Energy Commission Publication # 100-03-010. Place on line August 7, 2003. http://www.energy.ca.gov/reports/2003-08-07_100-03-010.PDF

[5] Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements. California Energy Commission Publication # 100-04-005D, http://www.energy.ca.gov/2004_policy_update/documents/2004-08-26_workshop/2004-08-04_100-04-005D.PDF, Revised August 13, 2004.